



CENTRE FOR ADVANCED ENGINEERING • CHRISTCHURCH • NEW ZEALAND

Electricity Supply & Demand to 2015

Sixth Edition - October 2002

jointly published by

SINCLAIR KNIGHT MERZ

&

CAE

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Electricity Supply & Demand to 2015 — Sixth Edition

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In 1998, Leyland Consultants merged with Sinclair Knight Merz, Australia's largest consultant in the fields of electric power engineering, environmental engineering, transport, mining and materials handling.

In 1999, Sinclair Knight Merz merged its operations in New Zealand with Kingston Morrison.

Sinclair Knight Merz have been involved in most of the small hydro-electric power schemes built in New Zealand since 1974. The firm has gained recognition as a leading consultant and innovator in power generation, energy technology and the design and operation of power systems.

In 1976, they carried out a state-of-the-art review of combined-cycle power generation, which led to NZED choosing combined-cycle technology for a station at Waiau Pa rather than a gas-fired steam plant. Unfortunately, the government of the day then decided to build the Motunui gas-to-gasoline plant instead.

Since then, Sinclair Knight Merz have worked on designing and upgrading large and small hydropower schemes, thermal power stations and cogeneration plant in New Zealand and overseas.

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CAE at a Glance

- is a not-for-profit organisation, established in 1987
- has a well-established, proven record of achievement
- is based at the University of Canterbury campus
- is concerned with issues of national and international importance
- is helping to develop new solutions through advancing engineering knowledge and practice
- is helping inform and educate New Zealand communities about technology matters.

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To advance New Zealand's economic growth and social progress through broadening national understanding of emerging technologies and facilitating early adoption of advanced technology solutions.

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Historically, CAE activities have involved strong participation and financial support by industry and the engineering profession. Much of its work has been directed at projects that go beyond conventional engineering practice so as to create new perspectives on emerging technology trends to New Zealand. Its strategy is to be seen as a neutral, far-sighted commentator on technology and engineering-related matters.

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By progressing knowledge and technological understanding, CAE is uniquely positioned to facilitate an expanding role for the engineering profession and to bring about a real change in the technological capability of New Zealand. The organisation offers well-established project management skills and a wide network of academic, research, professional and business links, both national and international. As a knowledge broker, CAE gathers, interprets and disseminates knowledge and information through the publication of books, the conduct of seminars and conferences, and via its website.

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Foreword

Since the major economic reforms of the 1980s, it has been difficult to obtain independent and regularly updated date information on New Zealand's future electricity needs and how these might be met.

To assist provision of this information, the Centre for Advance Engineering (CAE) in 1992 commissioned Leyland Consultants (now part of Sinclair Knight Merz) to undertake some initial modelling work to consider how expected increased demands for electricity could be met. This work was notable in that it not only highlighted New Zealand's vulnerability to electricity shortages in dry years, but also the need for continued investment in additional generation capacity to meet increasing demand for electricity. The work also drew attention to the consequences of continued reliance on Maui gas for electricity generation.

Now ten years and five editions later the message remains the same, except that it is now more urgent. The decline of the Maui gas resource means that New Zealand is now facing an unprecedented situation where, if nothing is done, there is a high risk of electricity shortages over the next few years.

Experience over the last 60 years of public energy supply has shown that it is prudent to plan for a one in 20 year dry year at least. This current review shows that by 2003, there will probably be serious shortages during a one in 15 year dry year, and by 2006 almost any reduction from normal year hydro generation will result in electricity shortages. By 2010, unless there is a change in current generation investment levels and patterns of energy use, there will not be sufficient generation capacity to meet normal-year requirements.

The message from these findings must be that urgent action is required to counter these risks. Unless these issues are dealt with expeditiously, productivity and investment in New Zealand will be jeopardised. The causes of the problems are complex and no single action will resolve them. Uniquely in this edition we propose a new scenario "*Kia mahi tahi tatou*" - all of us working together - which shows that it is possible to achieve a reliable electricity supply, with the majority coming from renewable resources, if we are prepared to work together as a nation to ease the transition from a simple reliance on Maui gas to a sustainable post-Maui era.

Above all, such a strategy requires that Government, public institutions, private companies and New Zealand society work together to resolve the issues. There may well be a wide variety of opinions on the information contained in this Sixth edition, but debate is important if we are to refine and develop a better understanding of New Zealand's future electricity requirements.

CAE is please to support the publication of this document. It expands the extensive current work being undertaken by CAE on a range of energy opportunities for New Zealand. We congratulate Bryan Leyland and his team at Sinclair Knight Merz for the depth and scope of their analysis. We also acknowledge with thanks the significant financial support given by a diverse range of stakeholders in the energy industry. Their support is vital to our ability to continue to present well-researched analysis and comment on a sector of the economy on which New Zealand's international competitiveness and standard of living heavily depend.



R J (George) Hooper
Executive Director
Centre for Advanced Engineering

Executive Summary

The primary objective of this review is to examine the ability of existing and proposed generating capacity to supply New Zealand's electricity demand to 2015. It reviews the remaining capacity of Maui, the probable reserves in other gas fields, and assesses the potential of our coal, hydropower, geothermal and other resources to see if they are capable of meeting our growing demand for electricity.

This review has been sponsored by a number of companies in New Zealand who have an interest in electricity supply and demand. Among these companies there is a consensus that we are at risk of serious shortages. However there are a wide range of views on whether or not the reforms and the electricity market have achieved their stated objectives. The views expressed in the report are those of the authors.

Over the last few years the output from the Maui gas field has declined faster than expected and it has now lost the capacity to supply large amounts of additional gas in a dry year. In the same period more than 400 MW of thermal reserve stations have been taken out of service and, last year, Contact postponed their proposed 400 MW Otahuhu C station, one of the reasons being uncertainty of future gas supplies¹.

There are only two new major generating projects in the pipeline: the 400 MW combined cycle unit at Huntly that is expected to be in service in 2006 and project Aqua in the South Island with 285 MW planned to commence operation in 2008 and another 285 MW planned for 2011. These projects will barely meet load growth.

The study concludes that New Zealand does not have enough reserve generating capacity to cope with a one in 20 drought from now on and existing and proposed stations will not be able to supply the normal year energy requirements beyond 2010.

The country appears to be facing a crisis situation: the dry year risk is high in 2003 and 2004 and extremely high after 2005 when there will be little reserve capacity available to meet even a one in five dry year.

Our whole economy, jobs and daily lives are totally dependent on a reliable supply of electricity. Yet no one in the industry or government has an obligation to formally review electricity supply and demand or to ensure continuing supply.

To examine what can be done to mitigate the risk, this review has developed, in addition to a baseline scenario, two scenarios for augmenting the generating capacity:

"Short term" Stations that could be built or upgraded in a relatively short time frame to mitigate the risk of shortages.

"Kia mahi tahi tatou" This scenario shows that if, as a nation, we were all prepared to work together to achieve this objective it would be possible to have a reliable supply of power with the majority coming from renewable resources. If we are not prepared to make this national effort, we are faced with a massive increase in the amount of coal we burn in a normal year, or a continuing series of severe power shortages.

"all of us working together"

These scenarios cover options for new generating plant that could be put into service if the government was prepared to take action to ensure that the necessary approvals were obtained without unreasonable delay. They go hand in hand with uprating the transmission capacity to ensure that the power they generate can get to where it is needed.

In a normal year, New Zealand needs sufficient capacity to ensure that demand can be met using power

¹ Note that the project is not cancelled; if Contact are able to obtain a sufficient gas supply, it will proceed.

stations designed to produce low cost electricity and, preferably, from renewable resources. This role can be filled by geothermal, hydropower, wind and the highly efficient gas-fired combined cycle stations. For normal year generation, the “short term” option includes:

- A number of geothermal projects that could contribute around 250 MW by 2005.
- Some potential for generation from coal seam methane from coal fields on the West Coast and Southland. These may be able to contribute up to 30 MW of base load generation by 2005.
- Burning gas reserves from the Kapuni field at higher rates over the next few years by diverting the gas to the Taranaki combined cycle station or to New Plymouth or to a 100-200 MW extension to the Fonterra co-generation plant at Hawera.
- Some small hydro and wind farms.

For dry years, we need power stations that have access to a supply of fuel that will allow them to generate ‘flat out’ for at least four months. Since Maui gas became available this role has been filled by stations like Huntly and New Plymouth burning large quantities of Maui gas. Maui can no longer supply large quantities of gas in a dry year and it is highly unlikely that any new gas fields will be able to do so. This leaves coal, oil or LNG/LPG shipped in from overseas as the only suitable fuels for dry year reserve power stations.

Huntly has always operated on both coal and gas and is set to burn increasing amounts of coal in a normal year as gas supplies reduce and the load increases. Soon it will have little or no spare capacity for a dry year. Oil-fired generation appears to be the only available backup for dry years occurring in the next three to five years and, in the longer term, for providing the reserve power needed for droughts in excess of, say, one in 15 years.

The output of New Plymouth will soon be limited by shortage of gas so it would be sensible to convert it to burn oil. This would allow the station to run at full output from 2004 onwards when we are seriously short of dry year reserves. A second alternative is to install oil-fired gas turbines at the existing Marsden A site. Finally commissioning the mothballed Marsden B could be considered but it is likely to be expensive because a new chimney and a complete new instrumentation and control system would be needed. As any oil-fired units would only operate in emergencies, the high cost of the oil fuel they burn would not be significant overall.

If the Government is prepared to take whatever action is needed to ensure that these projects proceed without undue delay, they would go a long way towards reducing the risk of severe shortages between now and 2008.

With the recent emphasis on renewable energy, our traditional renewable resources of hydropower and geothermal power must not be overlooked. Although hydropower development now seems to be “unfashionable” it must not be forgotten that the existing hydropower stations in New Zealand have given huge economic benefits. New Zealand is fortunate in that does not have the huge dams and artificial lakes needed in many other countries in order to exploit their hydropower potential.

For the “Kia mahi tahi tatou” scenario we have identified schemes with an aggregate capacity in excess of 3300 MW. This is made up of approximately 1500 MW of hydro, 100 MW of wind power, 550 MW of geothermal, 250 MW of Oil, 500 MW of coal and 50 MW of cogeneration. 2150 MW of the proposed capacity is renewable so that the fossil fuel stations can be reserved for a dry year. If the public believe that priority must be given to renewable generation and an adequate supply of power, these schemes should be environmentally acceptable to the majority of New Zealanders.

The 500 MW (i.e. 2 x250 or 3x170 MW units) of new coal-fired capacity could be built at:

- Marsden Point where there are existing transmission line, land and cooling water facilities.
- In the Waikato, where there are extensive coal reserves.
- Near Westport on the West Coast of the South Island close to the existing Stockton open cast coal mine and not far from the terminal point of a 220 kV line that was built from Kikiwa many years ago

to connect to a proposed West coast coal fired station.

- On the lignite coal fields in Southland, which represent New Zealand's largest energy resource.

An advantage of coal-fired stations sited in the South Island is that they would reduce the load on the DC link during a drought when large amounts of power are needed in the South Island to maintain the levels of the South Island lakes.

The study also considers demand side management as a solution to the dry year problem and concludes that demand side management would need to achieve an overall reduction in electricity consumption of 20 to 30% to offset the effects of a 40% drop in hydro-electric generation during a drought. In 1992, a concerted national effort by the general public, industry and commerce produced savings in the region of 10% to 15%, but with considerable sacrifice by New Zealand industrial, commercial and domestic consumers and an estimated cost to the economy of \$500 million. Last winter, the minister asked for public savings and industries reduced production as prices skyrocketed. Others ran expensive standby diesel generators for long periods.

There has been an expectation that price increases will reduce demand. In practice this has not happened to any great extent².

Demand side management is not likely to reduce electricity consumption by 10% or more without:

- major disruption to the economy and people's lives,
- accusations that the electricity generating companies have "engineered" the shortage in order to force up the spot price, and
- political uproar.

Even if it were acceptable for some existing industries to shut down during droughts, any company that needs, for instance, to decide if they should export logs or process the timber in New Zealand will regard the risk of a shut down during a drought as a significant disincentive.

The promoters of the wholesale electricity market^{3,4} and its operating company (M-Co) contended that market forces would ensure that new generating capacity would be provided when it is needed. This has not eventuated, and New Zealand is now faced with a high risk of serious electricity shortages.

There appear to be several factors underlying the failure of the market and the reforms to provide an adequate supply of power:

- Transpower is unable to provide an adequate transmission system.
- The market structure does not reward a generator who holds plant in reserve for a dry year.
- The market structure does not provide consistent long term price signals to flag the need for new capacity.
- The complex and time consuming approvals process means that embarking on a new generation project is a long term, high risk enterprise.

None of these problems can be solved by the electricity industry.

If we take the view that electricity is a "public good" (just like sewage, water and roading facilities) and that the consumers are entitled to a reliable supply at the lowest possible cost, then a new market structure can be contemplated. With this concept, competition is focused on the only obviously competitive section of the market – that of building, operating and maintaining generating plants – leaving the transmission, distribution and retailing under the supervision of a regulator.

² The value of electricity is much greater than its price and there is no alternative, so it is not surprising in that there is minimal demand side response over the range of politically (and economically) acceptable electricity prices.

³ "Towards a Competitive Wholesale Electricity Market", Final Report of the Wholesale Electricity Market Study, 19 October 1992.

⁴ "New Zealand's Wholesale Electricity Market - Draft Proposal for Evaluation", Report of the Wholesale Electricity Market Development Group, March 1994.

Given the problems experienced in markets similar to New Zealand's, where, in many cases, heavy handed regulation has been imposed to cap price spikes and to ensure that there is sufficient installed capacity, the suggested market structure should be considered as a serious alternative to further experiments aimed at fixing the shortcomings of the existing market.

To mitigate the risk of serious shortages, we believe that the Government should:

- 1 Assemble an industry wide team with access to information on all aspects of the New Zealand system so that they can make a more accurate model of supply and demand than we have been able to do. It will then be possible to define the magnitude of the risks and the best options for mitigating them.
- 2 Investigate the cost to our economy of a power shortage such as occurred in 1992 and compare it with the long-term cost of maintaining sufficient reserve capacity to limit such shortages to, for example, once in 15, 20 or 25 years.
- 3 Take whatever action is needed to change the Resource Management Act⁵, the Electricity Act, the ODV process and Transpower's statement of corporate intent etc., so that it is possible to increase the capacity of transmission system by upgrading lines and building new ones without facing unreasonable costs and delays.
- 4 Take whatever action is needed to expedite the development of our geothermal resources - which could add 250 MW to our generating capacity with in a few years and another 200 MW within seven years.
- 5 ensure that New Plymouth power station maintains its present capacity with four sets in operation into the foreseeable future.
- 6 Encourage Contact to install oil firing equipment into New Plymouth Power station so that, in an emergency, it can run at full output burning oil.
- 7 Take steps to expedite the development of the Pohokura and Kupe gas fields for power generation and provide open access to the Maui gas pipeline.
- 8 Investigate re-establishing generation at Marsden point where there is a site, a cooling water system and transmission and transformer capacity sufficient for 500 MW of oil fired reserve generation.
- 9 Investigate the costs and economics of wind power generation and other "new renewable" generation technologies and compare them to the alternative of continuing to develop the country's hydro and geothermal resources. The investigation should take into account the intermittent nature of the output from wind and solar generation and the consequent need for support from our hydropower stations, noting that, in order to do this, it is essential that the hydro stations are able to operate in a flexible manner.
- 10 Carry out a wide ranging review of the electricity market in New Zealand and other markets overseas to see if there is a market model which is better able to provide us with a reliable and economic supply of electricity. This review should also consider restricting competition to the most competitive part of the industry – that of building, owning and operating power generating facilities.

We strongly recommend that all the above options – and any others that may arise – be investigated on an urgent basis.

⁵ For instance by "calling in" projects for Ministerial review under the RMA.

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1: Introduction

This study provides an independent evaluation of future electricity supply and demand.

Its purpose is to:

- examine the ability of existing and proposed generating capacity to supply New Zealand's electricity demand
- review the remaining capacity of Maui and other gas fields, and assess the potential of our coal, hydropower, geothermal and other resources capable of meeting our growing demand for electricity
- provide a source of reference information on existing and future generation, and historical load growth.

It has been updated every two years or so since the early 1990s. From the beginning it has:

- warned about the need for more gas as the Maui field depleted
- recommended that the Government give someone the responsibility for monitoring supply and demand
- recommended that the Government should be prepared to act to avoid shortages that will damage the economy.

This study was carried out by Sinclair Knight Merz, in co-operation with of the Centre for Advanced Engineering. Comalco, Contact Energy, Genesis, Natural Gas Corporation, Solid Energy, Transpower, Mighty River Power, TrustPower, Orion Group and Westpower made financial contributions towards the cost of carrying out the work. Generation figures were provided by Energy Link, who collated them from data downloaded daily from the Transpower Information Exchange (TPIX). The Electricity Statistics Modelling Unit (ESMU) at the Ministry of Economic Development also contributed their Energy Data File information.

Among the generating companies which contributed to this study there is a consensus that we are at risk of serious shortages. However there are a wide range of views on whether or not the reforms and the electricity market have achieved their stated objectives. The views expressed in the report are those of the authors.

1.1 Present situation

Over the last few years the output from the Maui gas field has declined faster than expected and it has now lost the capacity to supply large amounts of additional gas in a dry year. In the same period more than 400 MW of thermal reserve stations⁶ have been taken out of service and, last year, Contact postponed their proposed 400 MW Otahuhu C station because of lack of gas.

Several stations have been commissioned in recent years mainly fuelled by natural gas. These include the Otahuhu B and Stratford combined-cycle stations, Southdown Cogeneration Facility, and industrial cogeneration projects in Te Rapa, Te Awamutu, Edgecumbe, Kinleith, Hawera and Glenbrook. There have also been some non-fossil fuel stations built in this time, including four geothermal stations, two mini hydro stations and two windfarms.

The country appears to be facing a crisis situation: the dry year risk is high in 2003 and 2004 and extremely high after 2005 when there will be little – if any – reserve capacity available to meet even a one in five dry year.

Unless decisive action is taken (or we have a series of abnormally wet years), from 2003 into the foreseeable future New Zealand will not have sufficient reserve capacity to meet a drought. In some

⁶ The open cycle gas turbines at Stratford and Whirinaki Power Stations, and one of the New Plymouth generators. A second generator at New Plymouth is due to be decommissioned in late 2003.

critical periods, a drop of only a few percent in hydro generation could cause a power crisis similar to that experienced in 2001. A dry year similar to the one in 1992 would result in power restrictions, blackouts and costs to the economy exceeding the \$500 million loss in 1992.

There are only two new major generating projects in the pipeline: the 400 MW combined cycle unit at Huntly that is expected to be in service in 2006 and project Aqua in the South Island with 285 MW planned to commence operation in 2008 and another 285 MW planned for 2011. Contact and NGC have stated that they would like to build new combined cycle stations but, unless there is a large gas find very soon, only one of the three combined cycle stations is likely to proceed.

When it is commissioned, the Huntly plant will do no more than cover the load growth between 2001 and 2006. So all it will do is return us – for one year – to the situation that prevailed this winter when New Zealand was at risk from a drought. Project Aqua will not even cover the load growth between 2006 and its commissioning.

The situation is exacerbated by:

- The long period required between the decision to build a new generating plant and its coming into service. This commences with a long and uncertain approvals process followed by the normal periods required for tendering, ordering plant and construction.
- Inadequate transmission capacity means that, as happened in 2001, some thermal plant will not be able to generate at full capacity when it is needed.
- The lack of (apart from this review) well researched publicly available projections of supply and demand which would have given advance warning of the problems we now face.
- The need for dry year reserve capacity to back up the increased hydro generation from Manapouri tailrace tunnel project and, later on, from project Aqua on the lower reaches of the Waitaki River.

Extra reserve capacity may also be needed to:

- backup the intermittent output of large-scale wind farms, and
- mitigate the loss of flexibility in the operation of the hydropower stations which has been – and still is being – imposed during hearings for the renewal of water rights.

New Zealand does not have enough reserve generating capacity to cope with a one in 20 drought from now on, and existing and proposed stations will not be able to supply the normal year energy requirements from 2010. Even without a sophisticated analysis, it is obvious that we urgently need additional generating capacity to replace our declining gas supplies and to meet the demand in a normal year, as well as power stations that can meet the need for additional generation in a dry year.

1.2 The need for reserve capacity

All electricity generation and transmission systems must have reserve capacity available to maintain supply in the event of breakdowns of generating plant, loss of major transmission lines, droughts or any other factor which may reduce capacity⁷.

Within the New Zealand system, the determination of an appropriate level of reserve capacity is particularly complex because a large proportion of the generation comes from hydro-electric stations. In a dry year⁸ the annual output of these stations may reduce by as much as 15%⁹. However, in the critical part of the dry season – April to July – when rainfall in the North Island is low and the South Island catchments are freezing up, the lost output may be much greater than 15%. By way of example, the drought in the South Island in 1991 forced the Manapouri station to severely restrict its generation and ECNZ had to re-commission Marsden A during the winter electricity shortage only a few months after it was shut down. During the worst of the drought the output of the hydropower stations was reduced by about 40%. This equates to a short fall of 2400 GWh of hydro generation in a dry year.

⁷ This is not spinning reserve, which is provided to cover only short-term generation outages.

⁸ In the past, a 'dry year' has been taken to be a 1 in 20 year event.

⁹ "Report of the Electricity Sector Planning Committee 1983" - Electricity Division

In addition, the limited reserve storage capacity of the hydro lakes (approximately 15% of the annual inflow or 12% of annual demand) is insufficient to carry water over from season to season and storage levels can change dramatically even from month to month.

In a normal year, New Zealand needs sufficient capacity to ensure that demand can be met using power stations designed to produce low cost electricity and, preferably, from renewable resources. This role can be filled by geothermal, hydropower, wind and the highly efficient gas-fired combined cycle stations.

For dry years, we need power stations which, preferably, have low capital costs and which have access to a reliable supply of fuel. Since Maui gas became available this role has been filled by stations like Huntly and New Plymouth burning large quantities of Maui gas which were well above the contracted quantities. This option is no longer available and it is highly unlikely that any new gas fields will be able to boost production during a dry year. This leaves coal, or imported oil or LNG/LPG, as the only suitable fuel for dry year reserve power stations.

In this edition the impact of dry seasons has been investigated over half year periods i.e. a reduction of 30% hydro generation from February to July. The effects of dry years have been shown by indicating the amount of reserve generation required to be held in reserve in a normal year to cover a one in 20 dry year.

1.3 Scenarios investigated

Past reviews have only considered generating plant that was proposed for construction or that have been investigated to the extent that they could be committed for construction when the need arises. These reviews specifically avoided speculating on what other stations could be built if the need arose.

This review has developed three scenarios:

| | |
|---|--|
| “Baseline” | Stations that are committed for construction or will probably be built in the near future. |
| “Short term” | Stations that could be built or upgraded in a relatively short time frame to mitigate the risk of shortages. |
| “Kia mahi tahi tatou” <i>“all of us working together”</i> | This scenario shows that if, as a nation, we were all prepared to work together to achieve this objective it would be possible to have a reliable supply of power with the majority coming from renewable resources. If we are not prepared to make this national effort, we are faced with a massive increase in the amount of coal we burn in a normal year, or a continuing series of severe power shortages. |

2: Sources of Data

2.1 Past power demands and usage

2.1.1 General

Data has been collected from a number of sources. Some is reliable, but in other cases the uncertainties are large and there are wide variations from one source to another. In particular, there are many opinions on the amount of gas available.

Earlier editions of this study relied on the “Annual Statistics Relating to Power Generation”. NZED and ECNZ recorded the daily outputs of their own stations, and the outputs of all the generating stations owned by electricity supply authorities.

Now, generation data from electricity suppliers and private electricity generation is more difficult to collect, but the data included in this report represents the most accurate information available. Generation figures for most of the large power stations were obtained from Transpower Information Exchange (TPIX) data supplied by Energy Link. The data records electricity injected to the grid at the various points of connection. It does not contain a record of generation direct into distribution networks i.e. the smaller power stations formerly belonging to electricity supply authorities and co-generation plants. Annual averages based on past production have been assumed for these stations.

The data is grouped into financial years, to March/April until 1992/93, and to June/July¹⁰ thereafter.

The model used in this study considers power presently generated and sold by the generating companies, power generated by private cogeneration plants, transmission losses in the Transpower system and proposed stations.

The committed and proposed power stations have been grouped into ‘Baseline’, ‘Short Term’ and “Kia mahi tahi tatou” scenarios. The “Kia mahi tahi tatou” scenario has been included to show that, with a determined national effort, it would be possible to increase generation from the renewable sources and limit coal burning to dry years.

2.1.2 Projected electricity demand

Projected electricity demand is modelled based on an assumed annual load growth of 1.8% (1.68% North Island and 2.0% South Island.) The 1.8% load growth predictions are shown in Chart 1 beginning in 1999/2000 (after the most recent historical demand figures). It is consistent with load growth figures published by the Ministry of Economic Development in their recent Energy Outlook publication in a baseline scenario that assumed 3% per annum GDP growth.

Average national load growth for the five years up to 2000 was about 60 MW per annum, but the increase in private generating capacity e.g. Te Rapa, Kinleith, Hawera (Fonterra) and others would have hidden the real load growth. In the last two years, the peak demand recorded by Transpower has increased by between 2 and 2.2%. No co-generation or other private plants have been built recently or are in the pipeline at the moment, so it is quite likely that Transpower’s figures represent the true underlying load growth.

2.1.3 Projected electricity generation

The amount of power that needs to be generated has been calculated by adding the system losses to the electricity sold by generating companies plus the generation from private generation plant. Table 2.1 shows the expected generation and how it would be split between hydro, thermal and other generation (cogeneration, wind, landfill gas etc.) stations in normal and dry years.

The intent of this report is to identify when extra generating capacity will be required to meet the load.

¹⁰ Due to change in ECNZ’s financial year, and hence generation data.

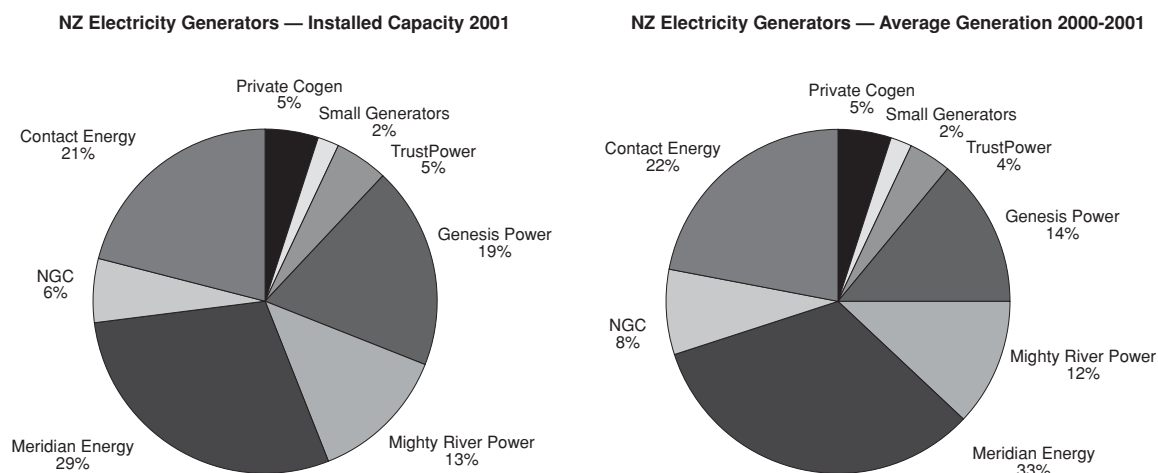


Figure 2.1: Installed capacity and average generation by generating companies

There are three factors in the equation: the increase in load, the capacity of existing and proposed power stations, and the capacity of the gas supply to sustain electricity generation. Once the load in a dry year can no longer be met, new generation is needed.

There is another factor that has not being taken into account in this model. This is the ability of the transmission system to transmit the power that could be generated. We have not modelled this because we do not have the information to do so. Until the power transmission system has been upgraded, transmission constraints will reduce the amount of power that can be generated.

2.2 Gas Supply

2.2.1 Gas model

The gas use model is based on MED figures from the latest Energy Data File, with Methanex assumed to use 82 PJ per annum until July 2004. Petrochem has been assumed to consume 6.3 PJ, industry (including cogeneration) 22 PJ and residential/commercial 16 PJ per annum. These two are assumed to increase by 1.8% per annum. The remaining gas is assumed to be available for electricity generation.

The study uses the best available figures for the reserves in Kupe, Rimu and Pohokura fields. Further exploration wells are needed to confirm the resource.

The Fourth Edition assumed that untapped fields such as Mangahewa and Kupe would have the potential to maintain adequate gas supply until beyond 2015. Since then, the estimates of available gas in Mangahewa have been drastically reduced, and there will not be enough gas for generation once Maui runs down. The only proven fields are the offshore Kupe field and the newly discovered Pohokura field just offshore of Waitara. The combined production of these two fields is much less than recent production from Maui.

The model does not take account of gas fields which may be discovered in the near future. There is no doubt that more gas will be found in New Zealand. Some will be from small onshore fields and there is a high probability that there will be large finds in offshore fields in deep water. However, as far as the period from now to 2010 is concerned, the best we can hope for is a number of small fields with an aggregate capacity similar to Pohokura.

2.2.2 Maui

The Third Edition assumed a decline of the Maui gas field from around 2005. Later editions indicated that the field was expected to last until about 2008. Since then the reserves have been re-evaluated and the best current information available indicates that the field will run down in the period 2005 to 2007¹¹.

¹¹ The reticulated gas market in New Zealand would still continue to be supplied by multiple smaller gas fields, well beyond the life of the Maui field.

| PROSPECTIVE ENERGY GENERATION (GWh pa) | | | | | | | | | |
|--|------------------|--------|---------|-------|-------------------------------------|--------|---------|-------|---------|
| Net Load Growth ~ 1.8% | | | | | Future Stations Included : Baseline | | | | |
| Year | Total Generation | Hydro | Thermal | Other | % Hydro | | | | |
| 1989-90 | 30,960 | 22,160 | 8,191 | 609 | 72% | | | | |
| 1990-91 | 31,575 | 23,206 | 7,743 | 626 | 73% | | | | |
| 1991-92 | 32,390 | 22,655 | 9,005 | 731 | 70% | | | | |
| 1992-93 | 31,523 | 20,954 | 9,839 | 730 | 66% | | | | |
| 1993-94 | 33,484 | 23,417 | 9,339 | 728 | 70% | | | | |
| 1994-95 | 34,425 | 27,021 | 6,429 | 975 | 78% | | | | |
| 1995-96 | 34,847 | 26,460 | 7,470 | 918 | 76% | | | | |
| 1996-97 | 35,656 | 23,707 | 10,901 | 1,048 | 66% | | | | |
| 1997-98 | 36,343 | 24,449 | 10,389 | 1,505 | 67% | | | | |
| 1999-00 | 37,618 | 23,447 | 12,054 | 2,118 | 62% | | | | |
| 2000-01 | 38,573 | 25,130 | 11,402 | 2,041 | 65% | | | | |
| | | | | | | | | | |
| Mean Year | | | | | Dry Year (85% of mean) | | | | |
| | | Hydro | Thermal | Other | % Hydro | Hydro | Thermal | Other | % Hydro |
| 2001-02 | 39,349 | 24,545 | 12,269 | 2,535 | 62% | 20,863 | 15,951 | 2,535 | 53% |
| 2002-03 | 39,991 | 24,576 | 12,880 | 2,535 | 61% | 20,890 | 16,566 | 2,535 | 52% |
| 2003-04 | 40,626 | 24,390 | 13,631 | 2,605 | 60% | 20,731 | 17,289 | 2,605 | 51% |
| 2004-05 | 41,291 | 24,413 | 14,273 | 2,605 | 59% | 20,751 | 17,935 | 2,605 | 50% |
| 2005-06 | 41,952 | 24,257 | 15,090 | 2,605 | 58% | 20,618 | 18,729 | 2,605 | 49% |
| 2006-07 | 42,641 | 24,280 | 15,756 | 2,605 | 57% | 20,638 | 19,398 | 2,605 | 48% |
| 2007-08 | 43,343 | 24,303 | 16,435 | 2,605 | 56% | 20,658 | 20,080 | 2,605 | 48% |
| 2008-09 | 44,158 | 25,446 | 16,107 | 2,605 | 58% | 21,629 | 19,924 | 2,605 | 49% |
| 2009-10 | 44,886 | 25,470 | 16,811 | 2,605 | 57% | 21,649 | 20,632 | 2,605 | 48% |
| 2010-11 | 45,626 | 25,493 | 17,529 | 2,605 | 56% | 21,669 | 21,353 | 2,605 | 47% |
| 2011-12 | 46,481 | 26,636 | 17,240 | 2,605 | 57% | 22,641 | 21,236 | 2,605 | 49% |
| 2012-13 | 47,249 | 26,659 | 17,985 | 2,605 | 56% | 22,660 | 21,983 | 2,605 | 48% |
| 2013-14 | 48,030 | 26,683 | 18,743 | 2,605 | 56% | 22,680 | 22,745 | 2,605 | 47% |
| 2014-15 | 48,826 | 26,706 | 19,515 | 2,605 | 55% | 22,700 | 23,521 | 2,605 | 46% |
| 2015-16 | 49,636 | 26,729 | 20,302 | 2,605 | 54% | 22,720 | 24,311 | 2,605 | 46% |
| 2016-17 | 50,461 | 26,752 | 21,104 | 2,605 | 53% | 22,740 | 25,116 | 2,605 | 45% |
| 2017-18 | 51,301 | 26,776 | 21,920 | 2,605 | 52% | 22,759 | 25,936 | 2,605 | 44% |
| 2018-19 | 52,156 | 26,799 | 22,752 | 2,605 | 51% | 22,779 | 26,771 | 2,605 | 44% |
| 2019-20 | 53,026 | 26,822 | 23,599 | 2,605 | 51% | 22,799 | 27,622 | 2,605 | 43% |

Table 2.1: Historical and predicted generation by generating plant

This model is based on the 767 PJ of gas reserves said to be available as of the first of October 2001 on page 122 of the Energy Data File 2002, which quoted a media statement by Maui Development Limited in November 2001.

A formal re-determination of the reserves is proceeding at the moment and, from the information we have been able to gather, the general expectation is that this is more likely to lead to a reduction in reserves than an increase.

2.2.3 Pohokura

A joint venture¹² of Fletcher Challenge Energy, Preussag Energie, Shell and Todd has been drilling the Pohokura-1 gas prospect over the 1999-2000 summer. Pohokura is in shallow water just north of the onshore Mangahewa-2 gas find. FCE estimates that this field could contain over 500 billion cubic feet of recoverable gas.

¹² *ibid.* pg 7.

The model assumes that 600 PJ of recoverable gas is contained in this field and that production begins in 2006 initially at 20 PJ per annum and ramping up to a steady 60 PJ over the next two years. 2006 is the earliest possible date and this could be delayed because the Resource Management Act process has not yet been completed.

The model assumes that this gas is used for power generation but we note that it could also be used to extend the life of the Methanex plants.

2.2.4 *Mangahewa*

In 1998, the Mangahewa gas find was reported in the media as potentially being able to provide 2000 PJ of gas plus associated condensate. These forecasts made it the second biggest gas reserve after Maui. However, the gas is trapped in impervious rock and sands, making it difficult to recover. The current estimates are that it contains 119 PJ of gas, less than 6% of the original estimate.

The pessimistic model assumes that this field would begin producing gas at about 8 PJ per annum from now.

2.2.5 *Kupe*

The offshore Kupe field has not yet gone into production, and is not likely to do so until the gas reserves at Maui begin to run out. Reserves of gas¹³ at Kupe were estimated to be 285 PJ. This is about 15% of known gas reserves.

The model assumes that production at Kupe begins in 2007 at 20 PJ per annum.

2.2.6 *Kapuni*

Estimates of the gas reserves at Kapuni are about 237 PJ as at 1 January 2001. About 20 PJ of gas has been sold from this field annually with the bulk of its output committed to petrochemical production.

The gas contains about 40% carbon dioxide, which requires it to be used in the immediate vicinity (Stratford, Kapuni, New Plymouth or Hawera), as it cannot be transported via the Maui gas transmission system without removal of the CO₂.

The model assumes a constant production of 20 PJ per annum till 2006 and ramping down until final depletion of the field by 2020.

2.2.7 *Kaimiro, TAWN, McKee, Ngatoro, Piakau*

Between them, these fields had net reserves of 158 PJ as of 1 January 2001 with an annual net production of 24 PJ per annum. These are assumed to run down within 10 to 12 years.

2.2.8 *Rimu*

A few years ago, Houston-based Swift Energy New Zealand Ltd struck oil at its wildcat well, Rimu-A1 near Hawera. The well is estimated to contain at least 100 million barrels of oil. The gas to oil ratio has been calculated¹⁴ at approximately 3000 cubic feet per barrel. Thus the well could have potential gas reserves of 400 PJ or more.

The model assumes there is 200 PJ of gas reserves in Rimu, and production is assumed to begin in 2002 at 8 PJ per annum.

2.2.9 *Kauhauroa, East Coast*

Gas¹⁵ was discovered in the East Coast Basin in 1998 by the Westech-Orion joint venture. The first well drilled by the venture, Kauhauroa-1, 10 km north of Wairoa produced an initial stabilised flow of 11.5 million cubic feet of gas per day. The second well, Awatere-1 on the outskirts of Wairoa also found gas,

¹³ NZ Petroleum News Issue 49, July 2002

¹⁴ "Swift Energy finds oil and gas", NZ Petroleum News, 23 December 1999.

¹⁵ "Explore New Zealand Petroleum", Crown Minerals, Ministry of Commerce, January 2000 pp 13-16.

tested 3.1 million cubic feet per day. No further finds were made after this, so Westech-Orion carried out a series of four appraisal wells around Kauhauroa in 1999 and later continued testing at the Kauhauroa-1 site.

Because of the high level of uncertainty we have not allowed for any supply of gas from this field.

2.3 Coal

There are an estimated 15 billion tonnes of coal reserves in New Zealand of which 8.6 billion tonnes is judged to be economically recoverable¹⁶. About 90% of the reserves by weight are in the South Island (75% by energy content). The 8.6 billion tonnes represents approximately 120,000PJ of energy.

Coal production in New Zealand for 2001 was 3.9 million tonnes. About 500,000 tonnes (11 PJ) of coal is used for electricity generation (excluding cogeneration), although this figure is subject to fluctuation. The only thermal power station using coal feedstock is Genesis-owned Huntly Power Station, which can burn gas and coal.

The coal reserves in Rotowaro amount to about 17 million tonnes (340PJ). There are about 3 million tonnes (60PJ) available from the open cast mine at Maramarua and about 300m tonnes of reserves (6,600PJ) accessible with underground mining.

Rotowaro opencasts and the existing Huntly East underground mine could supply at least 1.5 million tonnes (30 PJ) pa for at least 10 years from readily available coal. The model assumes that a maximum of 5800 GWh (2 million tonnes) per annum will be available from burning coal at the existing Huntly Power Station, corresponding to the output of the station at 66% plant factor¹⁷.

A new coal fired power station situated near Westport on the West Coast the South Island and used for hydro firming in a dry year, is also a distinct possibility. It could be supplied from the Stockton coalfield which has 230 m tonnes of reserves. Some of the coal is high value metallurgical (coking) coal which is exported. Lower grade coal which is extracted to get access to the high grade coal is available for power generation and there is also other steaming coal available. Altogether, 1 million tonnes pa could be available for power generation. The coal can be stockpiled easily, which is important for a dry year firming station.

However it should be noted that increasing pressure under international agreements to limit carbon dioxide emissions may restrict the use of coal for electricity generation, although the application of the latest coal technology would reduce the emissions significantly.

2.4 Power Stations

2.4.1 General

In this model power generation is divided between South Island hydro-electric stations and North Island hydro-electric, thermal, geothermal and cogeneration stations. Proposed North and South Island stations that do not fall into the above categories (i.e. wind, landfill gas), have been listed as alternative power. Table 2.2 lists the installed capacity and assumed annual generation capability for these stations.

2.4.2 Hydro-electric stations

Generation

The average generation data over the past seven years has been used to predict the future generation of the hydroelectric power stations. Where information was unavailable from the generating company or from TPIX data, average historical generation has been used.

Efficiency improvements

Allowances have been made for the increased output that will result from upgrading existing hydro-

¹⁶ "Energy Data File July 1999", Section C, Energy Modelling and Statistics Unit, Ministry of Commerce.

¹⁷ As Huntly is close to the top of the merit order, it is likely to run at lower loads during spring and early summer.

| Station | Location | Capacity MW | Plant Factor | Generation GWh |
|---------------------------|--|----------------|-----------------|-------------------|
| NI Hydro | | | | |
| Bay of Plenty Electricity | Aniwhenua | 25 | 58% | 127 |
| Eastland Network | Waihi | 5 | 30% | 13 |
| Genesis Power | Kourarau | 1 | 65% | 4 |
| Genesis Power | Rangipo | 120 | 49% | 519 |
| Genesis Power | Tokaanu | 210 | 42% | 769 |
| Genesis Power | Waikaremoana (to be sold by June 2000) | 135 | 37% | 440 |
| King Country Energy | Kuratau | 6 | 53% | 28 |
| King Country Energy | Mangahao | 38 | 37% | 124 |
| King Country Energy | Piriaka | 1 | 79% | 9 |
| King Country Energy | Wairere Falls & Mokauti | 7 | 44% | 25 |
| Mighty River Power | Arapuni | 175 | 64% | 989 |
| Mighty River Power | Aratiatia | 84 | 50% | 365 |
| Mighty River Power | Atiamuri | 79 | 48% | 331 |
| Mighty River Power | Karapiro | 96 | 67% | 562 |
| Mighty River Power | Maraetai | 360 | 31% | 979 |
| Mighty River Power | Ohakuri | 112 | 47% | 464 |
| Mighty River Power | Waipapa | 51 | 64% | 284 |
| Mighty River Power | Whakamaru | 100 | 72% | 635 |
| New Zealand Energy | Opunake & Raetihi | 1 | 71% | 3 |
| Northpower | Wairua Falls | 3 | 79% | 21 |
| TrustPower | Hinemaiaia | 7 | 65% | 37 |
| TrustPower | Kaimai Hydro | 45 | 45% | 176 |
| TrustPower | Mangorei & Motukawa | 9 | 58% | 47 |
| TrustPower | Matahina | 72 | 37% | 231 |
| TrustPower | Patea | 33 | 41% | 117 |
| TrustPower | Wheao | 26 | 57% | 130 |
| NI Hydro Total | | 1,800 | 47% | 7,429 |
| SI Hydro | | | | |
| Alpine Energy | Opuha River | 7 | 49% | 30 |
| Contact Energy | Clyde | 432 | 56% | 2,122 |
| Contact Energy | Roxburgh | 320 | 60% | 1,680 |
| Meridian Energy | Aviemore | 220 | 52% | 993 |
| Meridian Energy | Benmore | 540 | 52% | 2,469 |
| Meridian Energy | Manapouri (550 GWh 2nd tunnel) | 760 | 75% | 4,967 |
| Meridian Energy | Ohau A | 248 | 55% | 1,189 |
| Meridian Energy | Ohau B | 212 | 55% | 1,013 |
| Meridian Energy | Ohau C | 212 | 54% | 995 |
| Meridian Energy | Tekapo A | 25 | 63% | 140 |
| Meridian Energy | Tekapo B | 160 | 61% | 852 |
| Meridian Energy | Waitaki | 105 | 59% | 543 |
| New Zealand Energy | Fox, Turnbull & Okuru (diesel) | 2 | 47% | 7 |
| Pioneer Generation | Glenorchy, Wye, Meg, Fraser | 8 | 92% | 61 |
| Pioneer Generation | Teviot (4 stations) | 11 | 65% | 59 |
| Pioneer Generation | Horseshoe Bend | 4 | 51% | 18 |
| NGC | Cobb | 32 | 68% | 191 |
| TrustPower | Arnold | 3 | 91% | 24 |
| TrustPower | Coleridge | 35 | 81% | 244 |
| TrustPower | Highbank | 25 | 37% | 83 |
| TrustPower | Monowai | 6 | 76% | 40 |
| TrustPower | Montalto | 2 | 60% | 10 |
| TrustPower | Paerau & Patearoa | 12 | 57% | 61 |
| TrustPower | Waihopai & Branch (2 stns) | 12 | 87% | 91 |
| TrustPower | Waipori | 81 | 26% | 182 |
| TrustPower | West Coast Hydro (7 stations) | 12 | 54% | 59 |
| SI Hydro Total | | 3,485 | 59% | 18,123 |

Table 2.2: Installed capacities and annual generation in 2001
(continued next page)

| Station | Location | Capacity MW | Plant Factor | Generation GWh |
|-----------------------------------|-----------------------------|----------------|-----------------|-------------------|
| Thermal | | | | |
| Contact Energy | New Plymouth | 400 | 58% | 2043 |
| Contact Energy | Otahuhu A | 0 | 0% | 0 |
| Contact Energy | Otahuhu B | 365 | 29% | 920 |
| Contact Energy | Stratford (decommissioned) | 0 | 0% | 0 |
| Contact Energy | Whirinaki | 0 | 0% | 0 |
| Genesis Power | Huntly | 1,000 | 41% | 3613 |
| NGC/MRP | Southdown | 118 | 89% | 918 |
| NGC | Stratford Power CC | 354 | 75% | 2,334 |
| Thermal Total | | 2,237 | 50% | 9,828 |
| Geothermal | | | | |
| Bay of Plenty Electricity | TOI & TG2, Kawerau | 6 | 78% | 42 |
| Contact Energy | Poihipi | 53 | 48% | 224 |
| Contact Energy | Ohaaki | 68 | 83% | 492 |
| Contact Energy | Wairakei | 165 | 90% | 1,302 |
| Top Energy | Ngawha Springs | 12.0 | 74% | 78 |
| Tuaropaki Trust | Mokai | 65 | 70% | 400 |
| Mighty River Power | Rotokawa | 24 | 90% | 189 |
| Geothermal Total | | 393 | 79% | 2,726 |
| Cogeneration | | | | |
| Bay of Plenty Electricity | Edgecumbe Cogen | 10 | 61% | 54 |
| Bay of Plenty Electricity/NGC | Kapuni | 25 | 61% | 133 |
| Duke Energy | Glenbrook MHF & Kilns Cogen | 94 | 58% | 477 |
| Contact Energy/NZ Coop | Te Rapa | 45 | 62% | 245 |
| Genesis/Anchor Products | Te Awamutu | 52 | 42% | 192 |
| Genesis/Carter Holt Harvey | Kinleith Mill | 40 | 48% | 168 |
| Fonterra | Hawera | 65 | 33% | 189 |
| Tasman Pulp & Paper | Kawerau Mill | 39 | 80% | 271 |
| Various | Small Bottoming Cycle Cogen | 26 | 31% | 69 |
| Various | Small Gas Turbine Cogen | 21 | 35% | 62 |
| Various | Small Topping Cycle Cogen | 28 | 65% | 162 |
| Cogeneration Total | | 444 | 52% | 2,022 |
| Wind & Alternative | | | | |
| Genesis Power | Haunui Wind Farm | 3.5 | 46% | 14 |
| Meridian Energy | Wellington Wind Turbine | 0.2 | 51% | 1 |
| Mighty River Power | Rosedale/Greenmount | 8.3 | 83% | 60 |
| Hutt City Council/Envirowaste | Silverstream | 2.7 | 92% | 22 |
| TrustPower | Tararua Windfarm | 32.0 | 48% | 135 |
| Various | Small Biogas Cogeneration | 12 | 27% | 28 |
| Wind and Alternative Total | | 58.5 | 51% | 260 |
| Total | | 8,398 | 51% | 37,345 |

Table 2.2: Installed capacities and annual generation in 2001 (continued)

electric stations. Increases of about 2.5% in MW output and 1.75% in annual generation (GWh) have been assumed to occur between now and 2015.

Water rights losses

There is a requirement on the four ex-ECNZ generating companies¹⁸ and other owners of hydro stations to re-apply for all their existing water rights by 2002. At a 1991 Hydrological Society forum, Dr R J Aspden

¹⁸ Including Contact Energy.

predicted in his paper “Electricity Resources and Demand in New Zealand” that overall there could be a reduction of 2400 GWh pa (10% of existing hydro generation) in their allowable water use as a result of the renewal process.

In 1994 Dr Aspden revised his predictions. The maximum likely loss in generation was estimated at 1420 GWh pa. Dr Aspden still considered this to be reasonable in 1996, and it has been retained for this edition as there has been no further investigation into water rights losses since then.

To give an example, when ECNZ lost their appeal regarding water diverted from the Wanganui River, an additional 120 GWh per annum of fossil fuel generation was required.

Recent water rights hearings have imposed – or are in the process of imposing – restrictions on operation that will result in lost generation and loss of flexibility.

If as assumed, the reconsenting process reduces the generating companies’ rights to divert and store water, the overall loss in generation (going back a number of years) could be over 1400 GWh pa. This loss will almost certainly have to be made up by burning more coal and to pay for this, the cost of electricity will increase. Additional carbon dioxide will also be released into the atmosphere. The inevitable result is that we will burn more coal.

2.4.3 Thermal power stations

The largest thermal stations currently operating in New Zealand are:

- Genesis Power Huntly coal/gas-fired steam station (1000 MW)
- Contact Energy New Plymouth gas-fired steam station (400 MW) decreasing to 300 MW at the end of 2003. Whether or not it closes down will be reviewed in 2006
- Contact Energy Otahuhu B gas-fired combined-cycle station (365 MW)
- NGC Stratford gas-fired combined-cycle station (354 MW)
- NGC/MRP Southdown gas-fired combined-cycle station (118 MW).

This report assumes that all of these stations (including New Plymouth) will be available to meet New Zealand’s future energy needs to 2015.

The following thermal stations were built for use during dry years and emergencies but, apart from Otahuhu A, are no longer available:

- Contact Energy Whirinaki diesel fuelled gas turbine station (162 MW) which was dismantled in 2001 and shipped to Australia
- Contact Energy Stratford gas turbine station (198 MW). Also shipped to Australia;
- Contact Energy Otahuhu A gas turbine station (40 MW) which is held as backup to Otahuhu B.

The thermal stations are described in more detail in Section 2.5.1.

Marsden A oil-fired steam station was last used during the 1992 drought and one unit was scrapped in 1997. The other unit runs as a synchronous condenser. Marsden B has never been commissioned and has had its chimney knocked down. Meremere is now being scrapped.

2.4.4 Geothermal power stations

The geothermal stations at Wairakei and Ohaaki generate 165 MW and 48 MW (derated from 120 MW) respectively. These stations normally operate on base load with a very high load factor. Hence the amount of electricity generated annually is high in relation to the installed capacity.

Added into the model is the TOI and TG2 geothermal stations at Kawerau owned by Bay of Plenty Electricity, which have been operating since 1989. Also, since the third edition, four new geothermal stations have been built.

Poihipi (53 MW)

Poihipi (previously McLachlan) Power Station commenced operation in May 1997 near Taupo. The station was built by a joint venture between Mercury Energy and Geotherm Energy. Its annual output is about 220 GWh and is constrained by the level of geothermal steam available under its resource consents. The output is expected to increase to 348 GWh when additional steam becomes available. On 30 December 1999, Contact Energy¹⁹ signed an agreement to purchase the land and assets of Mercury Geotherm, which also includes an uninstalled and refurbished generating plant for a 52 MW geothermal station.

Rotokawa (27 MW)

Power New Zealand, in association with the Ngati Tauhu's Tauhara North No. 2 Trust, commissioned a 27 MW geothermal station at Rotokawa in October 1997 with an annual output of about 230 GWh. The station consists of a 14 MW steam turbine, and three nominally 5 MW binary sets that use pentane gas as a working fluid. Two are heated by low-pressure steam and the other by brine. Due to the electricity reforms, Power New Zealand sold their share of the station to TransAlta, who then on sold it to Mighty River Power on 31 January 2000.

Ngawha Springs (9.6 MW)

In July 1998, network operator Top Energy in conjunction with Tai Tokerau Trust commissioned a 9.6 MW_{net} geothermal station at Ngawha Springs, Northland. The station consists of two identical 4.65 MW_{net} (5.6 MW_{gross}) binary cycle turbine generators. The average annual output of the station is about 95 GWh.

Mokai (55 MW)

In mid February 2000, a joint venture of Tuaropaki Trust and Mighty River Power commissioned the 55 MW Mokai geothermal station near Taupo. The annual output of the station was 320 GWh in 2000 and 400 GWh in 2001. Mighty River Power have an operations and maintenance contract for running of the station, and a hedge contract for a portion of the station's output.²⁰

2.5 Gas-fired Generation

Before the addition of Stratford and Otahuhu B combined-cycle stations, electricity generation from gas (not including cogeneration) was about 7000 GWh per annum, which is about 20% of total generation. Since then the annual electricity generation from gas-fired stations has been as high as 8400 GWh per annum.

The model predicts that, as the gas supply declines, New Plymouth's ability to generate will be constrained by gas supply. No new gas-fired generation is allowed for, because there is no reliable evidence that adequate gas supplies will be available for existing stations, let alone new.

2.5.1 Fossil fuel-fired stations**Otahuhu B combined-cycle (365 MW)**

The station is owned by Contact Energy who took it over in January 2000. It is located adjacent to the existing Otahuhu A plant. The unit has an efficiency of 58% and generates about 3000 GWh per annum, approximately 9% of New Zealand's electricity requirements. The generator transformer failed in 2000 but the station was back in service in time for the 2001 electricity shortage. It generated reliably throughout the shortage.

Stratford combined-cycle (350 MW)

Mercury Energy, Fletcher Challenge Energy, and TransAlta commissioned this combined-cycle station in Stratford in June 1998. The station has a capacity of 350 MW with an annual output of about 2800 GWh. As a result of the electricity reforms, TransAlta obtained full ownership of the station. It has since been purchased by NGC.

¹⁹ "Contact Energy Buys Geothermal Station", Press Release 30 December 1999, Contact Energy website.

²⁰ "ECNZ Welcomes Involvement in Tuaropaki Geothermal Station Development", ECNZ Media Statements, 9 February 1998.

Southdown cogeneration facility (125 MW)

The Southdown Cogeneration Facility was commissioned at the end of 1996 by Mercury Energy (now Vector), TransAlta and Enerco (now Orion). It was the first combined-cycle plant to be commissioned in New Zealand. It has two 45 MW gas turbines and a 35 MW steam turbine. It is designed to supply about 170,000 tonnes of process steam annually to local industry, making it a cogeneration plant.

Mercury Energy's share of the station was taken over by Auckland network company, Vector who were obliged to sell under the reforms. It is now owned by NGC and MRP.

Huntly (4 x 250 MW)

The Huntly station is able to run all units on either coal or gas and each of the four boilers can switch from one fuel to another in an hour. Water is taken from the Waikato River for cooling, and is then passed through an oxygenation weir before being returned to the river.

Water resource consents governing Huntly specify that water in the Waikato River downstream of the station cannot rise above 27°C. This may constrain the output of Huntly during hot weather when the river flows are low.

New Plymouth (4 x 120 MW)

New Plymouth was commissioned as an oil-fired station with five 120 MW units, and later converted to burn gas as well. In the past Huntly has been used in preference to New Plymouth and in 1994 and 1995 New Plymouth operated at a load factor of less than 20%. However, in the last three years New Plymouth has been operating at 55% plant factor.

When Contact Energy was granted resource consents for Otahuhu B power station in April 1997, the air discharge consent was appealed by Greenpeace based on its concerns about CO₂ emissions. Under an agreement with Greenpeace, Contact mothballed one unit when Otahuhu B was commissioned, and agreed to mothball another unit at the end of 2003. Contact will review the future of the station in 2006 and, as result, it may – or may not – be shut down shortly after. In the model the capacity of New Plymouth has been reduced to 400 MW, and to 300 MW in 2003/4. It then continues to operate until 2015.

The equipment used for oil burning has been decommissioned.

Whirinaki GT (3 x 54 MW)

Whirinaki was a gas turbine station operating on diesel fuel. Originally there were four sets: one set was removed in 1995 for cogeneration at Te Awamutu and in 2001 the remaining three sets were dismantled and shipped to Victoria, Australia.

Stratford GT (4 x 50 MW)

Stratford had four units. These units were dismantled in 2001 and shipped to Australia.

Otahuhu A (2 x 45 MW derated to 40 MW)

Otahuhu A has two aero-based gas turbine units that operate on diesel fuel. It is only used in emergencies. The station is also used for system voltage support by running the generators as synchronous condensers. The units are not suitable for base load operation because the high exhaust gas temperature of the Olympus gas generators damages the power turbines. It is held available as emergency backup in the event of the loss of the Otahuhu B station.

2.5.2 Existing alternative stations

Silverstream (2.7 MW)

Silverstream is a landfill gas project owned by MRP and Hutt City Council. It was commissioned in 1995, and has been included in the existing stations under 'alternatives'.

Rosedale-Greenmount (8.3 MW)

This is another landfill gas project that was commissioned in 1992. It was originally owned by Mercury Energy and was purchased in 1999 by Mighty River Power when they bought Mercury Energy's retail business.

Tararua Windfarm (32 MW)

In March 1999 CentralPower commissioned a 32 MW wind farm on the western flank of the Tararua ranges. It has a total of 48 turbines, and an expected annual output of 135 GWh. A further 50 turbines with a capacity of 36 MW and output of 150 GWh are possible by 2007. As a result of the electricity reforms, the windfarm was sold to TrustPower.

Hau Nui Windfarm (3.5 MW)

Wairarapa Electricity commissioned Hau Nui windfarm near Martinborough in 1996. It consists of seven wind turbines and produces about 14 GWh annually (45% plant factor). It was sold to Genesis Power in 1999 as a result of the Electricity Reform Bill. In late 1999, Genesis Power upgraded the wind turbines with new 500 kW Enercon E40 turbines, which are quieter and more productive than earlier designs.

Genesis are now embarking on a 16 MW extension to the farm.

Wellington Wind Turbine (225 kW)

A wind turbine (originally built by ECNZ) has been operating near Brooklyn, Wellington since March 1993, with an annual output of 1 GWh. This was the first stage in ECNZ's planned programme of wind energy evaluation. The wind turbine was allocated to Meridian Energy in the 1999 split of ECNZ.

*2.5.3 Cogeneration plant***Glenbrook (110 MW)**

New Zealand Steel completed a second cogeneration plant at its Glenbrook site based on the recovery of waste heat from the kilns in 1998. It has a capacity of 72 MW with an annual generation of approximately 350 GWh. The original MHF cogeneration plant consists of two 18.8 MW generators, which have an annual output of about 150 GWh. The cogeneration plants were sold to Duke Energy International in January 1999.

Kinleith (40 MW)

Carter Holt Harvey and ECNZ in a joint venture commissioned a cogeneration plant at Carter Holt Harvey's Kinleith site. It has a capacity of 40 MW, and an annual generation of 274 GWh. It burns wood fuel supplemented by natural gas and has been in service since the beginning of 1998. ECNZ's share of the venture was allocated to Genesis Power in the 1999 split of ECNZ.

Te Awamutu (2 x 26 MW)

ECNZ and Anchor Products commissioned a 26 MW gas turbine and waste heat boiler at Te Awamutu in 1996. It uses one of the double-ended gas turbines from Whirinaki and the other gas turbine is able to generate an additional 26 MW of peak power. In the 1999 split of ECNZ, Te Awamutu was allocated to Genesis Power.

Kapuni (25 MW)

Bay of Plenty Electricity and Natural Gas Corporation commissioned a cogeneration plant at Kapuni in 1997. Its first full year of operation was 1998/99 when it generated 119 GWh. It is expected to generate about 175 GWh per annum.

Hawera cogeneration (4 x 10 MW + 1 x 28 MW)

Fonterra (formerly Kiwi Dairy Company) have commissioned a 4 x 10 MW gas turbine power plant in Hawera. Two were installed in 1996 and two in 1997. Each gas turbine is associated with a waste heat

boiler which generates process steam for the factory. A 28 MW passout steam turbine was commissioned in August 1998. The output from the plant is about 230 GWh pa.

Te Rapa cogeneration (45 MW)

Contact Energy²¹ in a joint venture with the NZ Co-operative Dairy Company (now Fonterra) have recently commissioned one of the largest gas-fired cogeneration plants in New Zealand. The 45 MW plant provides steam and electricity for the Te Rapa factory with excess electricity being exported to the national grid. It generates about 290 GWh per annum.

2.5.4 Planned stations and upgrades

Waitaki and Manapouri A/RC

In 1999 Meridian Energy commissioned a \$50 million automation and remote control (A/RC) upgrade of the Waitaki hydropower scheme. The project introduced automation and remote control systems for the eight Waitaki hydro-electric power stations, allowing all the stations to be controlled from Twizel. A 1% efficiency increase is expected from this upgrade, which would equate to an increase of about 125 GWh per annum.

Meridian Energy has also begun an A/RC project at Manapouri. The increase in generation could be about 50 GWh per annum.

Aviemore new runners

Meridian Energy²² is upgrading Aviemore Hydropower Station with the installation of four new turbine runners. This increased efficiency and energy generation by about 50 GWh per annum. The runners were installed in 2000.

Manapouri second tailrace tunnel

Meridian Energy began the tunnelling phase of their second tailrace tunnel project at Manapouri in 1998. The project was completed in mid 2002 and increased the station output from 590 MW to 760 MW. It will generate an extra 550 GWh per annum. The performance of the new tunnel is better than expected.

Project Aqua

“Project Aqua” is a 570 MW development on the lower Waitaki River where there is a fall of about 200 m over a distance of about 60 km. The potential for development using a series of canals and power stations has been under consideration for thirty years or so. A number of concepts were developed but the project never proceeded because of high costs and, at that time, a surplus of generating capacity in the South Island.

Over the last few years, Meridian Energy have revisited the project and they are now proposing to build a scheme with six power stations each generating about 95 MW. Unlike previous proposals, each power station has a single turbine and this and other design refinements have resulted in a cost substantially lower than that arrived at during previous studies.

This scheme is now proceeding through its environmental approvals stage and, if the project proceeds as hoped, the first three stations will begin generating 285 MW (1600 GWh) in July 2008. The other three stations are expected to begin generation in July 2011.

This project will provide a major block of renewable generation at a time when it will be much needed. However, the project is likely to be required to leave a substantial flow of water in the lower Waitaki River, and, as a result, the station output will drop by more than the 15%, typical of other hydro schemes during a one in 20 year drought. Therefore, some additional thermal firming capacity will be needed in dry years.

²¹ From Contact Half Year Report for Period to 31 March 1998.

²² “\$6 Million Upgrade for Aviemore Power Station”, ECNZ Media Statements, 26 June 1997.

Huntly E3P

Genesis are believed to be close to placing an order for a new gas-fired combined cycle station with a nominal capacity of about 380 MW. This station will be built at the existing Huntly site. The final decision to proceed is likely to be made as soon as Genesis have confirmed access to the Maui pipeline, a commitment to develop the Kupe gas field and a contract for the supply of gas from the new Pohokura field. When it comes on line, this station will more or less cover the expected load growth between now and its commissioning. We have assumed that it will be online in 2006.

3: Power Generation Model

3.1 Introduction

New Zealand power generation has been modelled on a spreadsheet that takes into account all the power stations of all generating companies, known private cogeneration plants and possible future generation.

The capacity and losses of the DC Link, hydro generation in dry and normal years, the availability of fuel for the fossil fuel-fired stations and the maximum output that can be expected from the fossil fuel-fired stations are used as input data. The proposed generation projects are grouped into 'Baseline' (Committed+Probable), 'Short term' and 'Kia mahi tahi tatou' scenarios. The last two groups can be included or excluded as desired. The future stations are also grouped by type into hydro, geothermal, cogeneration, fossil fuel and alternative, with each type being used in the spreadsheet along with existing stations. Printouts of sections of the spreadsheet are included in Appendices 1 and 2 as an indication of the process that was followed.

The starting point of the calculation is the annual energy sold in the North and South Islands. To this is added the North and South Island transmission losses estimated at 5%, and the DC link losses estimated at 9% of power transmitted. Distribution losses are not included in the model, as the "electricity sold" figure is based on past sales from generating companies to distribution companies.

The model assumes that the transmission system will be able to transmit all the power that can be generated. It is well known that the New Zealand transmission system has a number of constraints that, during the winter of 2001, prevented some of the thermal stations generating at full capacity. It is now generally accepted that a major upgrade of the transmission system is required. However, the Electricity Act and the way the Resource Management Act is implemented and other factors make it extremely difficult, if not impossible, to upgrade existing lines or to build new ones.

Private cogeneration plants have been added to give a clearer figure of the total amount of electricity generation required to meet the New Zealand load. Hydro, cogeneration, geothermal, and alternative generation are then subtracted from the required generation to give the amount of electricity that must be generated by fossil fuel stations.

The spreadsheet incorporates logic and algorithms based on an assumed merit order of the stations and the availability of various fuels. This determines how much power will be generated by each thermal station and what fuel or mix of fuels will be used. Gas is selected up to the available limit before coal is used. Except for the 'Short term' and "Kia mahi tahi tatou" scenarios, oil-fired generation is no longer considered as there are no longer any base load stations capable of burning oil.

The merit order for the gas-fired stations in the model gives priority to the new combined-cycle stations over Huntly and New Plymouth. Remaining Maui gas is allocated to Huntly unless it is required to burn coal to meet the energy demand, in which case the gas is diverted to New Plymouth.

However in a market situation, our merit order is unlikely to apply. Our allocation of gas is designed to maximize efficiency of use. An allocation based on the various gas supply contracts would probably use more gas and generate less electricity.

3.2 Modelling dry years

To model dry years, it has been assumed that they will occur in both the North Island and the South Island at the same time, which is a worst case scenario. This reduction in hydro generation generally occurs within a six-month dry period in which hydro generation is reduced by 30% (equivalent to 15% over a full year).

There are three charts (6, 7 and 8) showing the effect of the reduction in the output of the hydro stations in dry years. One shows the reduction in South island hydro generation and the others show the dry year

reserves that should be available in a normal year. The chart for the South Island also shows the effects of a drought on the use of the DC link. During a drought, large amounts of power have to be transferred from the North Island to the South Island and, in some cases the requirement may be greater than the link capacity.

The second chart illustrates the effect of a drought on the whole system. To do this, we have calculated the amount of reserve generation that should be available in a normal year so that, if a dry year occurred, the demand would just be met. This reserve quantity has been stacked above the line showing the demand on the normal year generation chart. Another line shows the amount of reserve generation predicted to be available to provide the reserve generation needed in a dry year. The difference between the two lines gives a graphic illustration of the extent to which we are, or are not, at risk from a one in 20 dry year in the future.

The calculation of the available reserve capacity assumes that all thermal plant is available and will run at 90% availability for four months during a dry period. This is an optimistic assumption and so the third chart shows the reserve generation available if it is assumed that, for one reason or another, the available generation has been reduced by 1000 GWh. Such a loss of generation could be caused by one of the major generating units failing, or by transmission constraints or a combination of the two. (1000 GWh corresponds to the output of a 250 MW unit at Huntly for six months or for the loss of one of the combined cycle units for about four months.) We believe that this is a realistic assumption.

3.3 Other inputs to the model

Generation losses as a result of the renewal of water rights are also included in the model. These are phased in until 2006, up to a total of 1420 GWh.

The spreadsheet includes an allowance for the increased output resulting from the upgrading and refurbishment of existing hydropower stations by assuming that the output of existing hydro schemes will increase by about 2.5% over the period until 2015. There is also some scope for increasing output from existing hydro-electric stations by improving water management practices.

As mentioned in Section 2.3, the coal supply for Huntly is assumed to be sufficient to run the station at full output and generating 5800 GWh per annum.

3.4 Peak demands

The ability of the system to meet peak demands also needs to be investigated. The spreadsheet calculates the peak demand, firm capacity and reserve capacity. Peak demand is calculated from the annual generation using historical load factors. This is considered sufficiently accurate for this study.

Peak reserve capacity is defined as the amount of plant that needs to be held in reserve to cover contingencies such as breakdowns and dry seasons. The precise calculation of peak reserve capacity for the New Zealand system depends on the probability of failure of the various types of generating plant, the loss of peak output capability of the hydro-electric stations during droughts and the perceived cost of failing to supply. Such calculations are beyond the scope of this study.

For the purposes of this study, we have estimated the peak reserve capacity as set out below.

Thermal stations:

- Installed capacity less 1 x 385 MW set (Otahuhu B Combined-Cycle), plus 15% of the installed capacity unavailable due to maintenance or other reasons.

Hydro schemes:

- 7.5% unavailable due to maintenance or other reasons.
- An additional 5% unavailable to allow for an assumed loss of capacity during dry years. This 5% is consistent with the fact that, in the 1991 dry season, the 590 MW Manapouri station was operating at much less than 300 MW.
- An additional 3% unavailable to allow for the loss of capacity as hydro generation companies lose a

substantial amount of water and operational flexibility as a result of the water right hearings. This is not in addition to Dr Aspden's assessed water rights loss, as his predictions are for annual generation (GWh) and not for capacities (MW).

DC link transmission losses (in MW) are included in the peak demand by assuming that the losses have a load factor of 0.5. This may be a conservative estimate when the South Island hydro stations are being used to provide peak power to the North Island.

When aggregated, these allowances amount to a little less than 22% of the peak demand. Various statements from ECNZ in the past indicate that they believed that a reserve capacity margin in the region of 22-24% was reasonable. It should be noted that this and previous studies show that generating capacity to satisfy the energy requirements of the system needs to be added several years in advance of when it would be needed to meet peak demand.

3.5 Results

The results of the calculations carried out by the spreadsheet are illustrated in the charts at the end of this text.

On the charts, the need for additional generating capacity is demonstrated by the appearance of an area shaded in black and labelled 'extra generation required'.

There are separate charts for normal and dry hydro years. As mentioned above, some of these charts show the amount of reserve generation that needs to be available to meet a one in 20 dry year and compare it with the amount of generation expected to be available.

3.5.1 Load growth

Chart 1 shows the 1.8% load growth considered by this report. This figure is in line with the predictions given in the Energy Data File. With 1.8% load growth, annual electricity usage will increase from about 37,200 GWh in 2001 to about 46,000 GWh in 2015. In line with recent trends, a load growth of 2% in the South Island and 1.68 % in the North Island has been assumed. This is probably realistic in the short-term but may not be realistic in the longer term. As there are many other major uncertainties in the longer term we do not think that this assumption will produce significant errors.

While evaluating other rates of load growth it was noticed that if the South Island growth is higher than 2%, then large power transfers are required from thermal power stations in the North Island to the South Island during a drought. These transfers exceeded the DC link capacity in a southwards direction.

The chart also shows how the total prospective electricity generation has been built up by adding the system losses to the electricity sold in the North and South Islands. The dip in generation due to the 1992 winter electricity shortage and the subsequent recovery in demand in the six years following that drought can be seen. The historical data available since the drought shows a 6% increase in the first year following the drought and 2% increases in the following years.

3.5.2 Gas supplies

Chart 2 shows the gas availability and usage profile used for the study. It assumes that Methanex shuts down in 2004 and that Pohokura commences production in July 2006. Kupe is assumed to commence production in January 2007. The chart shows a steady decline in the amount of gas available for power generation between now and 2010 when new discoveries may become available.

The profile is based on known fields and the best available information on their reserves and production rates. It makes no allowance for gas that may, or may not, be found in the future. Given the right incentives, the consensus of opinion is that there is a high probability of continuing gas discoveries. However, due to the long delay between discovery and production, it is most unlikely that any gas discovered in the near future would be available before 2010. It is therefore prudent to assume that the predictions for between now and 2010 are likely to eventuate.

The timing of the shut down in the Methanex plants is a critical factor in the availability of gas in the 2003 to 2008 period.

3.5.3 New Zealand generation capacity

Normal Hydro Inflows

Chart 3 shows total New Zealand generation with an assumed annual load growth of 1.8%, and with baseline stations included (committed + probable). The demand can be seen to be met by a successive 'merit order' of generation, i.e. hydro and cogeneration followed by geothermal and gas, and then coal. The chart shows the large proportion of generation being met by South Island hydropower in a normal year.

Chart 3 shows that, with normal hydro inflows, extra generation would be required to meet the load from 2009/10. The graph shows the steady increase of gas-fired generation up to a peak of about 10,000 GWh in 2005/6 before it steadily drops off as Maui gas runs out. By 2015, either 4000 GWh of new generation would be required or about 15 PJ per annum of gas would need to be found for the gas-fired stations.

Chart 4 shows generation in the North Island in normal years when an increasing amount of coal-fired generation is needed. By 2012 Huntly is generating its maximum capacity of 5800 GWh pa from coal. By then, the station will be nearly 40 years old and may not be able to maintain such a high per output.

Chart 5 shows generation in the South Island in a normal year. It shows the effect of Project Aqua coming on line and the level of transfers on the DC link as the South Island continues to supply the North Island with hydropower.

Dry years

Chart 6 shows the dramatic drop in generation that occurs in the South Island in a dry year. For the purposes of illustration, the axes of the chart have been scaled to show the situation as it would be in the dry six month period and ignores the second half of the year.

It shows that in any dry year from now on the South Island will not be able to supply sufficient hydropower to meet its own load and relies on imports from North Island thermal stations (shown as "DC link (going South)").

Chart 7 shows the same graph as Chart 3 but with the dry year reserve requirement and availability added. This graph shows that, right now, we do not have enough capacity to cover a one in 20 year drought. This situation gets worse year by year.

Chart 7 assumes that, during the final four months of a 6 month dry period, the thermal reserve stations will operate with an availability of 90%. Given the age of the plant involved, transmission constraints in Taranaki and other parts of the system which often limit generation, it is not at all certain that these stations could be relied on to generate at plant factors of 90% for four months.

In our opinion, Chart 8, which allows for plant breakdowns and/or system constraints which reduce generation by 1000 GWh, is the most realistic. It shows that by 2005 we will have less than half of the reserve capacity needed to meet a one in 20 year drought and by July 2009 we no longer have any reserves available for a drought.

3.5.4 Fossil fuel stations

Normal year

Chart 9 shows generation by fossil fuel stations. It highlights the effects of the fall-off in gas supplies and shows that by July 2005, after the new Huntly CCGT comes on-line, New Plymouth and the existing Huntly Power Station no longer have any gas available to them. It also shows the dramatic increase in coal-fired generation at Huntly.

Thermal reserve requirements

Chart 10 shows the additional thermal reserve capacity that needs to be available if we are to have sufficient thermal reserve plant for a one in 20 dry year. Looking at the critical period to July 2010, the reserve requirement increases from 200 MW in 2003 to 800 MW in 2010. Note that this is the plant that we should have **in addition to** the existing thermal reserve stations at Huntly and New Plymouth.

3.5.5 Capacity to meet peak demand

In addition to examining the energy generating capacity of the system (GWh), it is also necessary to check the ability of the system to meet the peak demand (MW) with an acceptable degree of reliability. Chart 11 shows the peak demand. It also shows the reserve and installed capacity with the baseline ('committed' and 'probable') future stations included, and the spare capacity for a 1.8% load growth.

In 1998/99, the commissioning of Stratford and Otahuhu B combined-cycle stations caused a large increase in total generating capacity. This decreased in the next year due to the decommissioning of Stratford open cycle gas turbine station and one of the New Plymouth sets. The only major increase since then has been the 170 MW Manapouri upgrade in mid 2002.

Chart 11 shows that with a 1.8% load growth, peak demand will exceed firm capacity from 2004. This implies that from 2010 new generating plant will be needed just to meet peak demand. But, before then, new plant will be needed to meet the energy requirements in normal and the dry years. Hence it can be concluded that capacity to meet peak demand is not the principal consideration in determining the need for new power stations.

4: Conclusions and Comments

4.1 Dry year risk

The country appears to be facing a crisis situation: the dry year risk is high in 2003 and 2004 and extremely high after 2005 when there will be little – if any – reserve capacity available to meet even a one in five dry year.

The conclusion from the above charts is that unless decisive action is taken (or we have a series of abnormally wet years), from 2003 into the foreseeable future New Zealand will not have sufficient reserve capacity to meet a drought. In some critical periods, a drop of only a few percent in hydro generation could cause a power crisis similar to that experienced in 2001. It also shows that a dry year similar to the one in 1992 would result in power restrictions, blackouts and costs to the economy exceeding the \$500 million loss in 1992.

We are in this situation because of a number of factors. These include:

- Maui gas reserves declining more rapidly than was expected a few years ago.
- The long period required between the decision to build a new generating plant and its coming into service. This commences with a long and uncertain approvals process followed by the normal periods required for tendering, ordering plant and construction.
- Inadequate transmission capacity (although our modelling has assumed that adequate transmission capacity is available, it is well known that this is not the case and, as happened in 2001, some thermal plant will not be able to generate at full capacity when it is needed).
- The lack of success in discovering gas to replace the Maui field.
- The effects of the electricity reforms which have resulted in no one (apart from this review) producing publicly available and well researched projections of supply and demand which would have given advance warning of the problems we now face.
- The market failing to provide reserve capacity.

4.2 New generating plant

4.2.1 Short-term options

There are only two new major generating projects in the pipeline: the 400 MW combined cycle unit at Huntly that is expected to be in service in 2006 and Project Aqua in the South Island with 285 MW planned to commence operation in 2008 and another 285 MW planned for 2011. When it is commissioned, the Huntly plant will do no more than cover the load growth between 2001 and 2006. So all it will do is return us – for one year – to the situation that prevailed this winter when New Zealand was at risk from a drought. Project Aqua will not even cover the load growth between 2006 and its commissioning.

We are aware of a number of options for new generating plant which could be put into service within the next two or three years if the government was prepared to take action to ensure that the necessary approvals etc were obtained without unreasonable delay.

These are:

- A number of geothermal projects where the exploration has already been done and, in some cases production wells are available. These could contribute around 70 MW by 2005 and 270 MW by 2010.
- A 100-500 MW West Coast coal-fired station.
- Some potential for generation from coal seam methane from coal fields on the West Coast and Southland. These could contribute up to 30 MW by 2005. Further investigations are needed to

confirm the potential which, in the long term, could be 100 MW or more.

- Gas reserves from the Kapuni field could be burned at higher rates over the next few years by diverting it to the Taranaki combined cycle station or to New Plymouth or to a 100-200 MW extension to the Fonterra co-generation plant at Hawera. Whichever option is chosen, at least 100 MW would be available by 2005. If the gas is to be diverted to TCC it would be necessary to solve the problem posed by the resource consents which put a very high penalty on CO₂ emissions.

If the government ensures that the approvals are expedited and these projects proceed, they would go a long way to reducing the risk of severe shortages between now and 2008.

All of the above projects provide the base load generation that is needed to meet the demand in a normal year. In a dry year, additional generation is needed to make up the shortfall from the hydropower stations. In the past, this shortfall has been found to be about 15 percent in a one in 20 dry year. As a result of the commissioning of the Manapouri tailrace tunnel project and Project Aqua, this percentage will increase slightly.

4.2.2 Coal-fired generation

Since Maui gas became available, the dry year shortfall has been made up by the gas-fired stations – some of which no longer exist – taking large quantities of additional gas out of the Maui field. We are now faced with a high probability that neither the Kupe field nor the new Pohokura field will be able to supply extra gas in a dry year due to the inherent characteristics of the fields. On top of that, we cannot assume that any new gas field will be able to provide this flexibility, so there appears to be no alternative but to rely on coal reserves to make up the dry year shortfall.

In some ways, coal is an ideal fuel for this because, unlike other fuels, it can be stockpiled. Also, if the station is associated with an open cast coal mine, production can be increased in a dry year.

During the 2001 hydro shortfall, about 2700 GWh of additional thermal generation was needed during the June and September quarters (compared with Huntly's generation capacity over a six month period of about 4000GWh). Gas consumption for electricity generation increased by about 55% (from an average of 49PJ to 76PJ) during these quarters and coal by about 37% (from 6.8PJ to 9.3PJ). If coal had been used instead of gas, about 1.5 million tonnes would have been needed. Increasing the output of a coal mine by 1.5 million tonnes over six months is not simple, especially on the scale of coal mining in New Zealand, and a 1.5 million tonne stockpile is not small²³.

The downside of using coal is the relatively high cost of a coal-fired power station compared to the alternative of an open cycle gas turbine. There are also increasing pressures under international agreements to limit carbon dioxide emissions may restrict the use of coal for electricity generation, although the application of the latest coal technology would reduce the emissions significantly.

There are an estimated 15 billion tonnes of coal resources in New Zealand of which 8.6 billion tonnes is judged to be economically recoverable²⁴. More than 80% of these resources are lignites in Otago and Southland. Coal production in New Zealand for 2001 was 3.9 million tonnes. About 500,000 tonnes of coal is used for electricity generation (excluding cogeneration), although this figure is subject to fluctuation.

There appear to be at least four potential locations for a new coal-fired power station.

- In the Waikato, where there are extensive coal reserves. The only thermal power station currently using coal feedstock is Genesis-owned Huntly Power Station, which can burn gas and coal. The tonnage required to run the station entirely on coal can probably be supplied by increasing production from the existing mining operations at Rotowaro and Huntly East.

New plant could be supplied from other opencastable reserves which include 18 Mt at Maramarua, 45 Mt at Onhinewai, and 35 Mt at Rotowaro. Waikato underground reserves are also substantial but are likely to be extremely expensive to extract. There are also 30 Mt of opencastable coal at Mokau in Taranaki. Virtually all of these reserves have already been evaluated by mining feasibility studies

²³ John Noble, The Independent Business Weekly, 28 August 2002.

²⁴ "Energy Data File July 1999", Section C, Energy Modelling and Statistics Unit, Ministry of Commerce.

carried out in the 1980s and constitute New Zealand's most strategically important coal resource. However, the barriers to rapid development of new, large scale mining operations in the region may be formidable.

- At Marsden Point where the transmission line, land and cooling water facilities are already available and could support a 500 MW station. Marsden also has a deep water harbour and so it would be easy to bring in bulk carriers transporting coal from Australia, Southeast Asia or the South Island, or barges from the South Island.
- Near Westport on the West coast of the South Island. A new coal-fired power station used mainly for hydro firming in a dry year could be supplied from the Buller coalfield which has 230 million tonnes of recoverable reserves. Some of the coal is high value metallurgical (coking) coal which is exported. Lower grade coal which is extracted to get access to the high grade coal is available for power generation and there is also other steaming coal available. Altogether, 1 million tonnes pa could be available for power generation. The coal can be stockpiled easily, which is important for a dry year firming station.

The coal resource could support a station of up to 500 MW that operated during peak periods in a normal year and at maximum output during a dry year. The station could be near to the existing Stockton open cast coal mine which produces in excess of one million tonnes of metallurgical coal each year. This site is not far from the terminal point of a 220 kV line that was built from Kikiwa many years ago to connect to a proposed West coast coal-fired station. This station was never built and the line now operates at 110 kV. To enable the existing line to transmit the output from a 500 MW station it will be necessary to build about 30 km of new line and string the second circuit conductors on the existing double circuit towers. A significant advantage of this option is that by supplying power to the upper part of the South Island it will reduce the load on the heavily loaded circuits feeding Christchurch and points north from Benmore.

- Based on the lignite coal fields in Southland and Otago. The station would have access to low cost coal and mining feasibility studies indicate that this is an attractive prospect. It is also unlikely that lignite can be stockpiled so the associated mining operation would be subject to highly fluctuating rates of production. On top of that, the output would be fed into an already over loaded transmission system.

One advantage of stations sited in the South Island is that they would reduce the load on the DC link during a drought when large amounts of power have to be sent South to maintain the levels of the South Island lakes. If the South Island load continues to grow at its present rate, it would not be long before the amount of power needed to be transmitted from thermal reserve stations in the North Island would exceed the capacity of the DC link when transmitting to the South Island.

4.2.3 Oil-fired generation

Oil-fired generation also is an option in the short-term and for providing the reserve power needed for droughts in excess of, say, one in 15 years. The study has shown that the output of New Plymouth will soon be limited by shortage of gas so it would be sensible to consider reinstating the oil-fired facilities that were previously installed in the station. This would allow the station to run at full output if needed during the period from 2004 onwards when we are seriously short of dry year reserves. Another opportunity for oil firing exists at Marsden Point where it would be worthwhile considering commissioning Marsden B running on oil. As a new chimney and a complete new instrumentation and control system will be needed, this may be expensive so it is probably better to install oil-fired gas turbines at the existing Marsden A site to where there are transformers already installed capable of carrying the output. As any oil-fired units at Marsden Point would only operate in emergencies, the high cost of the oil fuel they burn would not be significant overall.

We strongly recommend that all the above options – and any others that may arise – be investigated on an urgent basis.

4.3 Alternatives to coal-fired generation

Options for avoiding or delaying increasing long-term dependency on coal-fired generation during normal

years include:

- a large scale programme to encourage electricity conservation and energy efficiency
- the discovery of large quantities of natural gas
- the construction of new hydro schemes in the North and South Islands
- the construction of new geothermal stations
- encouraging the use of alternative energy sources if they can be shown to be economic
- giving urgency to refurbishing and uprating existing power stations
- nuclear power generation.

With the recent emphasis on renewable energy, our traditional renewable resources of hydropower and geothermal power must not be overlooked. Although hydropower development now seems to be “unfashionable” it must not be forgotten that the existing hydropower stations in New Zealand have given huge economic benefits.

New Zealand is exceptionally fortunate in that virtually all the rivers exploited for hydropower generation have large natural lakes in their headwaters. For this reason we do not have the huge dams and artificial lakes needed in many other countries in order to exploit their hydropower potential. Much of the bias against hydropower development seems to be based on reports of problems with a few large lakes in tropical areas. These problems do not apply to hydropower schemes in New Zealand so there is no logical justification for using them as a reason for abandoning development of our hydropower resources.

For the ‘Kia mahi tahi tatou’ scenario we have listed a number of known and notional schemes (including all the ‘possible’ schemes) with an aggregate capacity in excess of 3300 MW. This is made up of approximately 1500 MW of hydro, 100 MW of wind power, 550 MW of geothermal, 250 MW of oil, 500 MW of coal and 50 MW of cogeneration. To the best of our knowledge all these schemes are technically feasible and, if the public believe that priority must be given to renewable generation, should be environmentally acceptable to the majority of New Zealanders. 2150 MW of the new capacity is from renewable resources and the new fossil fuel stations are only required to generate in a dry a year. These schemes are listed in Table 4.1.

Chart 12 Shows that implementing the baseline and short-term schemes would supply our needs, provide security against a one in 20 dry year from 2006 to 2009 and mitigate the risk of dry year shortages prior to 2006.

Chart 13 Shows that these schemes plus adoption of Kia Mahi would supply our needs and provide security against a one in 20 dry year up to 2015.

During future resource consent hearings the postulated environmental benefit resulting from greater flows in the rivers and smaller variations in lake levels should be balanced carefully against the environmental effects and other disadvantages of increased generation from fossil fuels. It would be wrong to assume the loss in generation could be offset by energy conservation and/or increased energy efficiency: this is a completely separate issue. If conservation and efficiency are economic means of avoiding increased generation they should be pursued regardless of water rights issues.

4.4 The place of “new renewables”

“New renewables” such as wind, solar and biomass can make a useful contribution to our electricity needs if they can shown to be economic compared with established renewable technologies such as hydropower and geothermal, they should be exploited.

Wind and solar power are inherently intermittent and this reduces their value. It is interesting to compare them with geothermal and hydropower.

Geothermal power plants normally run at base load and their average generation is roughly equivalent to operation at full load for more than 90% of the time. New Zealand hydropower has an average

| Name | Plant Type | Capacity (MW) | Completed First Year of Gen by July | Plant Factor | Probability | Site | Output (GWh pa) |
|-------------------------------|------------|---------------|-------------------------------------|--------------|-------------|------|-----------------|
| Rotokawa 2 | Geothermal | 5 | 2003 | 92% | Baseline | NI | 40 |
| Mangahao | Hydro | 4 | 2003 | 31% | Baseline | NI | 11 |
| Hui Nui Extension | Wind | 16 | 2004 | 50% | Baseline | NI | 70 |
| Marsden Oil | Coal/Oil | 250 | 2004 | 90% | Short Term | NI | 1,971 |
| Aniwhenua | Hydro | 4 | 2004 | 14% | Short Term | NI | 5 |
| Tauhara | Geothermal | 12 | 2005 | 90% | Baseline | NI | 95 |
| Wairakei | Geothermal | 12 | 2005 | 90% | Baseline | NI | 95 |
| Mokai 2 | Geothermal | 40 | 2005 | 90% | Baseline | NI | 315 |
| Marsden Oil Refinery Cogen | Cogen | 50 | 2005 | 55% | Mahi Tahi | NI | 240 |
| Ohaaki | Geothermal | 20 | 2006 | 90% | Baseline | NI | 158 |
| Huntly | Nat.Gas | 400 | 2007 | 85% | Baseline | NI | 2,978 |
| Kawerau 2 | Geothermal | 100 | 2006 | 90% | Short Term | NI | 788 |
| Ngawha 2 | Geothermal | 30 | 2006 | 90% | Short Term | NI | 237 |
| Rotokawa 3 | Geothermal | 30 | 2006 | 92% | Short Term | NI | 242 |
| Saddle Road Windfarm | Wind | 10 | 2006 | 48% | Short Term | NI | 42 |
| Otahuhu 'C' | Nat.Gas | 0 | 2007 | 0% | Short Term | NI | 0 |
| Tararua Wind | Wind | 36 | 2007 | 48% | Short Term | NI | 150 |
| Kawerau 2 | Geothermal | 100 | 2008 | 90% | Mahi Tahi | NI | 788 |
| Rotokawa 4 | Geothermal | 30 | 2008 | 92% | Mahi Tahi | NI | 242 |
| Ngatanaraki | Geothermal | 50 | 2012 | 95% | Mahi Tahi | NI | 416 |
| Dobson | Hydro | 60 | 2008 | 62% | Mahi Tahi | SI | 326 |
| SI Concept Coal | Coal/Oil | 500 | 2008 | 90% | Short Term | SI | 3,942 |
| Lower Waitaki (Aqua Stage I) | Hydro | 285 | 2009 | 64% | Baseline | SI | 1,600 |
| Mokai 3 | Geothermal | 60 | 2009 | 90% | Mahi Tahi | NI | 473 |
| Pukaki | Hydro | 44 | 2010 | 34% | Mahi Tahi | SI | 132 |
| Luggate | Hydro | 100 | 2010 | 55% | Mahi Tahi | SI | 482 |
| Rotoma | Geothermal | 25 | 2010 | 91% | Short Term | NI | 200 |
| Hawea Gate | Hydro | 20 | 2010 | 40% | Short Term | SI | 70 |
| Makara Wind Farm | Wind | 6 | 2010 | 50% | Short Term | NI | 27 |
| Queensberry | Hydro | 166 | 2011 | 55% | Mahi Tahi | SI | 800 |
| Lower Waitaki (Aqua Stage II) | Hydro | 285 | 2012 | 64% | Baseline | SI | 1,600 |
| Rotokawa 5 | Geothermal | 30 | 2012 | 92% | Mahi Tahi | NI | 242 |
| Makara Wind Farm | Wind | 29 | 2012 | 50% | Mahi Tahi | NI | 128 |
| Upper & Lower Mohaka | Hydro | 200 | 2013 | 55% | Mahi Tahi | SI | 964 |
| Tuapeka | Hydro | 350 | 2014 | 52% | Mahi Tahi | SI | 1,600 |
| Whirinaki | Nat.Gas | 120 | 2020 | 85% | Short Term | NI | 894 |
| Rotokawa 2 | Geothermal | 5 | 2003 | 92% | Baseline | NI | 40 |
| Mangahao | Hydro | 4 | 2003 | 31% | Baseline | NI | 11 |
| Hui Nui Extension | Wind | 16 | 2004 | 50% | Baseline | NI | 70 |
| Marsden Oil | Coal/Oil | 250 | 2004 | 90% | Short Term | NI | 1,971 |
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| Saddle Road Windfarm | Wind | 10 | 2006 | 48% | Short Term | NI | 42 |
| Otahuhu 'C' | Nat.Gas | 0 | 2007 | 0% | Short Term | NI | 0 |
| Tararua Wind | Wind | 36 | 2007 | 48% | Short Term | NI | 150 |
| Kawerau 2 | Geothermal | 100 | 2008 | 90% | Mahi Tahi | NI | 788 |

Table 4.1: New stations considered and their associated scenario

| Name | Plant Type | Capacity (MW) | Completed First Year of Gen by July | Plant Factor | Probability | Site | Output (GWh pa) |
|-------------------------------|------------|---------------|-------------------------------------|--------------|-------------|------|-----------------|
| Rotokawa 4 | Geothermal | 30 | 2008 | 92% | Mahi Tahi | NI | 242 |
| Ngatanaraki | Geothermal | 50 | 2012 | 95% | Mahi Tahi | NI | 416 |
| Dobson | Hydro | 60 | 2008 | 62% | Mahi Tahi | SI | 326 |
| SI Concept Coal | Coal/Oil | 500 | 2008 | 90% | Short Term | SI | 3,942 |
| Lower Waitaki (Aqua Stage I) | Hydro | 285 | 2009 | 64% | Baseline | SI | 1,600 |
| Mokai 3 | Geothermal | 60 | 2009 | 90% | Mahi Tahi | NI | 473 |
| Pukaki | Hydro | 44 | 2010 | 34% | Mahi Tahi | SI | 132 |
| Luggate | Hydro | 100 | 2010 | 55% | Mahi Tahi | SI | 482 |
| Rotoma | Geothermal | 25 | 2010 | 91% | Short Term | NI | 200 |
| Hawea Gate | Hydro | 20 | 2010 | 40% | Short Term | SI | 70 |
| Makara Wind Farm | Wind | 6 | 2010 | 50% | Short Term | NI | 27 |
| Queensberry | Hydro | 166 | 2011 | 55% | Mahi Tahi | SI | 800 |
| Lower Waitaki (Aqua Stage II) | Hydro | 285 | 2012 | 64% | Baseline | SI | 1,600 |
| Rotokawa 5 | Geothermal | 30 | 2012 | 92% | Mahi Tahi | NI | 242 |
| Makara Wind Farm | Wind | 29 | 2012 | 50% | Mahi Tahi | NI | 128 |
| Upper & Lower Mohaka | Hydro | 200 | 2013 | 55% | Mahi Tahi | SI | 964 |
| Tuapeka | Hydro | 350 | 2014 | 52% | Mahi Tahi | SI | 1,600 |
| Whirinaki | Nat.Gas | 120 | 2020 | 85% | Short Term | NI | 894 |

Table 4.1: New stations considered and their associated scenario (continued)

generation of about 60% but it can be relied upon to deliver 100% power within seconds when it is needed during peak demand periods and system emergencies. This inherent reliability and flexibility makes it very valuable in a power system. Countries without hydropower often build large pumped storage stations to provide this flexibility.

The generation from wind farms in New Zealand is less than 50% of their nominal capacity. This means that a 200 MW wind farm would generate as much power as a 100 MW geothermal station. On top of that, it is not possible to predict how much power will be generated by a wind farm at any given time. This makes it very difficult for the system operator to schedule the remaining generation and requires a larger amount of expensive reserve capacity than would otherwise be required.

Solar power suffers even more from the same problems: it does not generate at night and generation during daylight hours is highly sensitive to cloud cover.

Nevertheless “new renewable” technologies can make a useful contribution to generation in New Zealand provided that they are backed up by a flexible power stations which can change load rapidly without incurring high costs. In theory, our 4500 MW of hydropower should fulfil this role. But to do this, they need to be allowed to operate with full flexibility. This means that the lake levels and flows downstream of the stations must be allowed to change rapidly. As discussed above, environmental restrictions being placed on our hydropower stations are restricting their ability to operate as needed.

The message is clear: if we wish to exploit wind and solar power we must allow flexible operation of our hydropower stations. If we do not, more water will be spilled and more coal will be burned.

5: Market Influences

5.1 Background

On 1 April 1999, the 1998 Electricity Industry Reform Act came into effect. Electricity generator ECNZ was split into three competing state-owned generators: Meridian Energy, Genesis Power and Mighty River Power. The other major state-owned generator, Contact Energy, was sold. At the same time, traditional electricity supply authorities were required to split their lines from their generating and retailing businesses.

Until the late 1980s power planning was a very public affair, with the Committee to Review Power Requirements producing its estimates of future power demand and the Power Planning Committee producing proposals for meeting that demand. These committees have been disbanded and the generating companies do not have any responsibility for providing a reliable and adequate supply.

On 1 October 1996, the New Zealand Electricity Market (NZEM) was established. It provides a mechanism for determining the spot price of electricity, and was expected to create economic signals for investment, efficiency and conservation²⁵.

The market allows generators to offer varying amounts of electricity via a pooled arrangement for dispatch and transmission through the national grid operated by Transpower. Retailers then purchase electricity from the pool to on sell to their retail customers. Buyers can protect themselves with hedge agreements with generators.

Our whole economy, jobs and daily lives are totally dependent on a reliable supply of electricity. Yet no one in the industry or government has an obligation to formally review electricity supply and demand or to ensure continuing supply. As a result, we no longer have sufficient reserve capacity to cover a dry year. This puts the growth of the New Zealand economy at risk.

It has been argued that market forces would ensure that new base load and dry year reserve generating capacity would be provided when it was needed. The electricity shortages and high prices in the winter of 2001 and the predictions of a high risk of shortages in any droughts in the near future predicted by this study indicates that the reforms and the market have failed to provide the generating plant and transmission capacity that is needed.

The uncertainties in available data and in modelling the effects of a dry season on the power system have meant that the scenarios presented here are not definitive. However, it does confirm that we are now facing a serious situation. More sophisticated modelling based on better information is needed so that the magnitude of the risk can be assessed and options developed for mitigating the risk.

5.2 Dry years and the market

The 1992 and 2001 winter electricity shortages²⁶ demonstrated that thermal plant and fuel supplies must be held in reserve to cater for a dry year and that we must have a transmission system capable of transmitting the power that can be generated. The 2001 crisis demonstrated that, contrary to expectations, the “demand side response” was insufficient to provide the reduction in load required to match the shortfall in generation. Given the high value of electricity compared to its price, and the very high cost of loss of supply (\$3000 to \$5000/MWh) this is not surprising.

If the reforms and the market had lived up to the expectations of their proponents, there would not have been an electricity crisis in 2001. There appear to be several factors underlying the failure of the market and the reforms to provide an adequate supply of power:

- Transpower is unable to provide an adequate transmission system.

²⁵ “The Market in Review October 1996 - December 1997”, EMCO.

²⁶ On 3 July 1992, ECNZ stated that hydro generation was down to 40% of total generation from its normal 75% and thermal generation had increased from 14% to 53%. (The missing percentages presumably come from the geothermal stations.)

- The market structure does not reward a generator who holds plant in reserve for a dry year.
- The market structure does not provide consistent long term price signals to flag the need for new capacity.
- The complex and time consuming approvals process means that embarking on a new generation project is a long term, high risk enterprise.

None of these problems can be solved by the electricity industry. Some proponents of the market believe that the reserve plant problem would be solved if retailers, generators and major users would enter into long term hedge contracts. Other believe that this is most unlikely to happen because the reforms have also given us retail competition. As result, no retailer can be certain of their customer demand in three years time – let alone 10. Major users are likely to be reluctant to give a long term commitment because of uncertainty in their long term market, ownership and, possibly, existence.

If we are to have the reliable supply of electricity that underpins our economy, then the only options appear to be (a) intervention by a regulator forcing Transpower to uprate its system and forcing the generators to maintain dry year reserves or (b) changing the market so that the interests of the industry and the economy are not in conflict.

The 1992 drought is said to have cost the economy about \$500 million. The 2001 crisis probably cost the economy something like \$200 million. \$200 million would have purchased 200 MW of reserve generating plant. Had it been available it would have gone a long way towards mitigating the crisis and would then have been available to mitigate dry years in the future. Alternatively, \$200 million would probably have eliminated the major transmission system constraints which, at times, prevented thermal generating plant from operating at its maximum capacity during the drought.

5.3 Alternatives to the present market structure

One option for an alternative market design is based on the view that electricity is a “public good” (just like sewage, water and roading facilities) and that the consumers are entitled to a reliable supply at the lowest possible cost²⁷. If this view is accepted, then a new market structure can be contemplated. With this concept, competition is limited to the only obviously competitive section of the market – that of building, operating and maintaining generating plants – leaving the transmission, distribution and retailing under the supervision of a regulator.

Such a market could have a “System Operator/Power Trader” entering into long-term contracts with the generators. These contracts would be based on the concept of a power station as a process plant when the owner/operator is paid for the use of his assets and for operation and maintenance with the fuel passing through at a cost that is reimbursed. With this concept, the stations can be state or privately owned and System Operator/Power Trader is in a position to centrally co-ordinate the operation of the system and optimise storage against thermal reserves to ensure that there is adequate reserve capacity. By so doing the SO/PT would recover the value that has been lost as result of the lack of co-ordination inherent in the existing market structure.²⁸ When new generating capacity, the SO/PT would go out to tender and contract for the construction and operation of the station on a competitive basis.

Given the problems experienced in markets similar to ours, where, in many cases, heavy handed regulation has been imposed to cap price spikes and to ensure that there is sufficient installed capacity, and in other markets such as the “New Electricity Trading Arrangements” in the United Kingdom, which has proved to be extremely complex and to provide powerful disincentives to distributed generation²⁹, a market structure such as suggested above should be considered as a serious alternative to further experiments aimed at fixing the shortcomings of the existing market.

²⁷ For example, the “speech from the throne”: “On energy infrastructure, new electricity generation capacity is needed and better gas arrangements are required for the long term. We need certainty of supply at reasonable prices, taking into account the need for energy efficiency and conservation. The government will be taking steps to ensure that appropriate industry structures, governance and rules are working to manage the electricity and gas industries effectively.”

²⁸ It is worth noting that there is nothing new in the contract arrangements that would be needed between the System Operator/Power Trader and the generators. A number of pumped storage stations – which must operate as and when the System Operator needs them – have contracts of this type and so do a number of thermal power stations where the power purchaser either supplies the fuel free of charge or pays a price with a component directly related to the fuel cost of the electricity generated.

²⁹ “Living with NETA” IEE Review July 2002 Page 32

5.4 Demand side management

In any discussion of demand side management there must be a clear understanding of the difference between load shifting and load shedding. Most demand side management consists of load shifting: that is, reducing the load in peak periods and increasing load in off peak periods. The net result is a reduction in peak demand but no change in the amount of energy used. Clearly, this type of demand side management is of no use during a dry year.

In a dry year, the demand side needs to shed load. This can be done in a number of ways. If it is done by increasing the price then, because the value of electricity is much higher than its price, the price has to go up by factor of five or ten before there is a noticeable reaction. Even then, response is limited to those whose tariffs and metering arrangements expose them directly to the high price. This, in effect excludes domestic and small commercial consumers who have their meters read once every two months or so. So, as happened in 2001, most of the load shedding is done by major users of electricity. In many cases, these are major productive industries that make a large contribution to the economy.

If demand side management could achieve an overall reduction in electricity consumption of 20 to 30% during a drought, it would offset the effects of a 40% drop in hydro-electric generation. In 1992, a concerted national effort by the general public, industry and commerce produced savings in the region of 10% to 15%, but with considerable sacrifice by New Zealand industrial, commercial and domestic consumers.

Demand side management is not likely to reduce electricity consumption by 10% or more without:

- major disruption to the economy and peoples' lives,
- accusations that the electricity generating companies have "engineered" the shortage in order to force up the spot price, and
- political uproar.

Proponents of large scale demand side management to appear to take the view that many of our productive businesses and industries would be prepared to shut down to reduce power costs during a drought. This implies a belief that the cost to the country of the lost production is less than the cost of providing reserve capacity to mitigate the effect of the drought. This does not appear to be the case and studies are needed to find out if it is true.

To give an example: on the face of it, arranging for the aluminium smelter to carry a stockpile of aluminium sufficient for, say, four months production would allow it to shed 500 MW of load during a drought. The reality is not so simple: experience in 1992, when a pot line was shut down, was that there were huge costs above those of the lost production in bringing the pot line back into normal production.

To give another example: the pulp and paper industry is based on long-term contracts requiring a constant supply of product. If they are forced to shut down due to the skyrocketing electricity prices (which, in themselves, are a signal that the market has failed) they will have to pay huge penalties and risk losing their contracts. In theory, hedges would solve this problem: in reality, they have failed to do so in New Zealand and overseas.

Even if it were acceptable for some existing industries to shut down during droughts, any company that needs, for instance, to decide if they should export logs or process the timber in New Zealand, will regard the risk of a shut down during a drought as a significant disincentive.

We need to remind ourselves that, for the last fifty years or more, New Zealand has had one of the most effective demand side management systems in the world: water heater control. This system can shift load from peak demand periods to off peak periods and it can also reduce demand by restricting the supply of hot water. In the past, water heater control combined by public-spirited efforts by domestic, commercial and industrial consumers has proved to be an efficient and effective way of reducing demand during the drought. As a result of the reforms, it is being used less effectively than before.

6: Recommendations

The study concludes that New Zealand does not have enough reserve generating capacity to cope with a 1 in 20 year drought from now on and existing and proposed stations will not be able to supply the normal year energy requirements beyond 2010.

To mitigate the risk of serious shortages, we believe that the Government should:

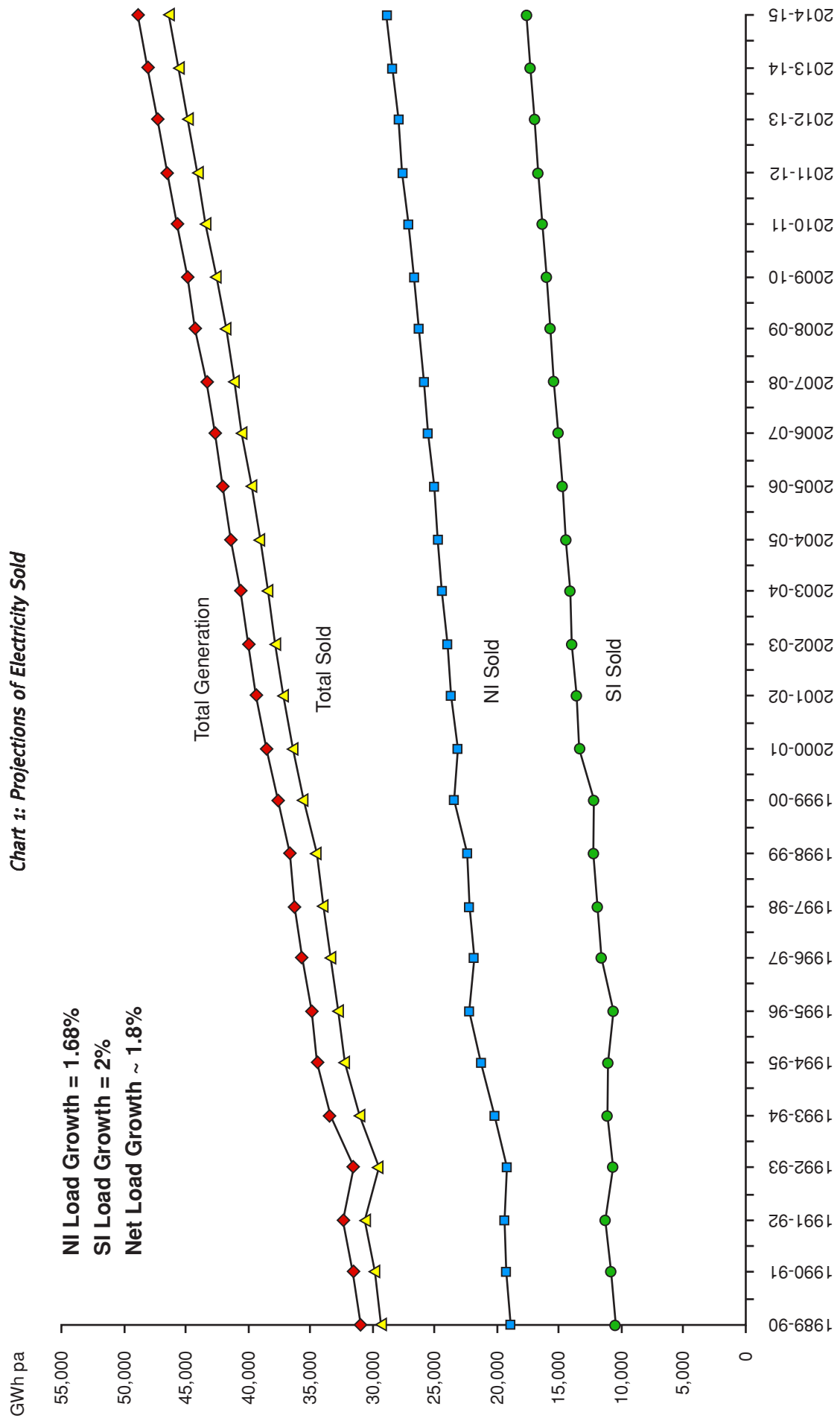
- 1 Assemble an industry wide team with access to information on all aspects of the New Zealand system so that they can make a more accurate model of supply and demand than we have been able to do. It will then be possible to define the magnitude of the risks and the best options for mitigating them.
- 2 Investigate the cost to our economy of a power shortage such as occurred in 1992 and compare it with the long-term cost of maintaining sufficient reserve capacity to limit such shortages to, for example, once in 15, 20 or 25 years.
- 3 Take whatever action is needed³⁰ to change the Resource Management Act, the Electricity Act, the ODV process and Transpower's statement of corporate intent etc., so that it is possible to increase the capacity of transmission system by uprating lines and building new ones without facing unreasonable costs and delays.
- 4 Take whatever action is needed to expedite the development of our geothermal resources, which could add 250 MW to our generating capacity with in a few years and another 200 MW within six years.
- 5 Ensure that New Plymouth power station maintains its present capacity with four sets in operation into the foreseeable future.
- 6 Encourage Contact to install oil firing equipment into New Plymouth Power station so that, in an emergency, it can run at full output burning oil.
- 7 Take steps to expedite the development of the Pohokura and Kupe gas fields for power generation and provide open access to the Maui gas pipeline.
- 8 Investigate re-establishing generation at Marsden Point where there is a site, a cooling water system and transmission and transformer capacity sufficient for 500 MW of oil fired reserve generation.
- 9 Investigate the costs and economics of wind power generation and other "new renewable" generation technologies and compare them to the alternative of continuing to develop the country's hydro and geothermal resources. The investigation should take into account the intermittent nature of the output from wind and solar generation and the consequent need for support from our hydropower stations, noting that, in order to do this, it is essential that the hydro stations are able to operate in a flexible manner.
- 10 Carry out a wide ranging review of the electricity market in New Zealand and other markets overseas to see if there is a market model which is better able to provide us with a reliable and economic supply of electricity. This review should also consider restricting competition to the most competitive part of the industry – that of building, owning and operating power generating facilities.

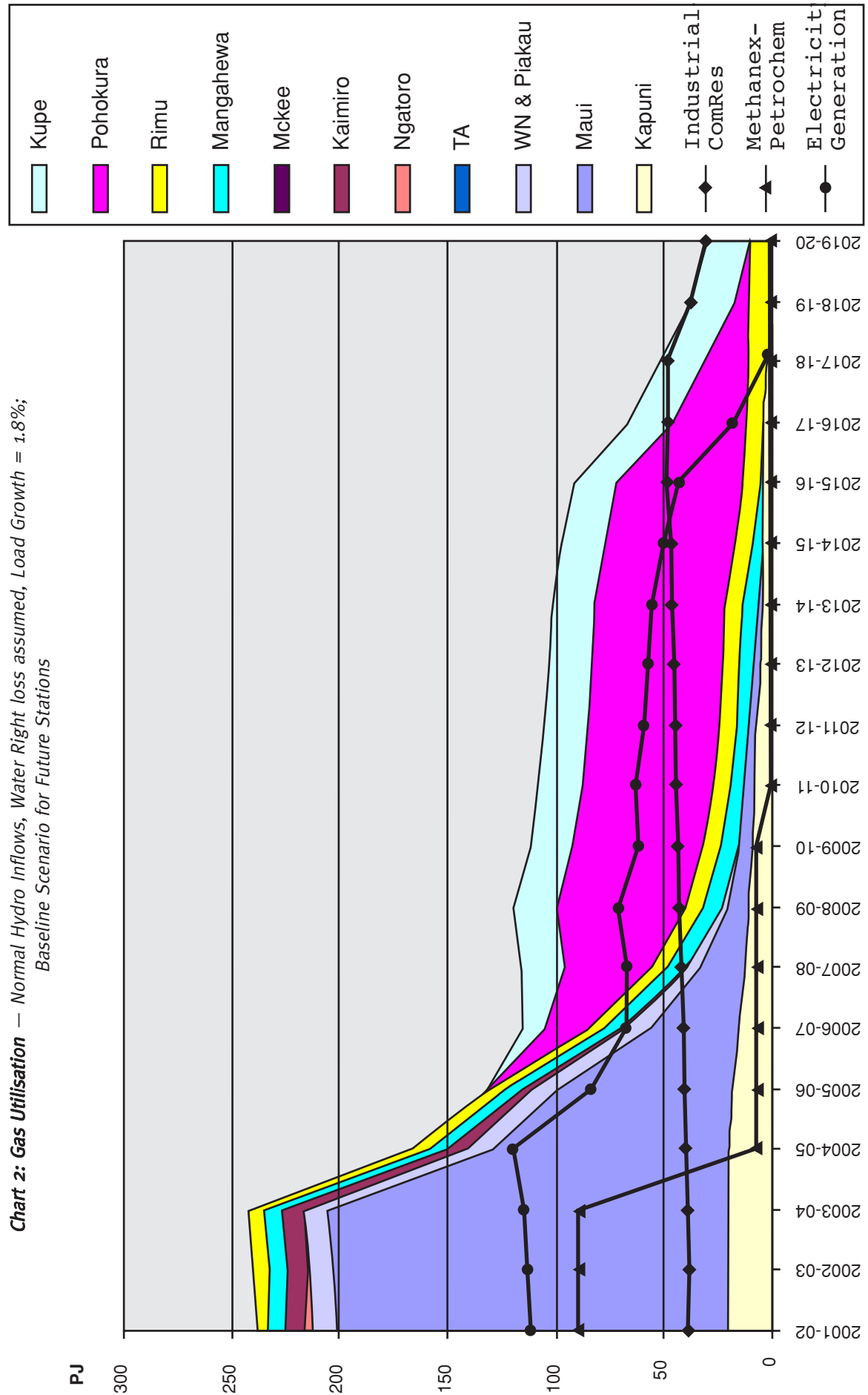
We strongly recommend that all the above options – and any others that may arise – be investigated on an urgent basis.

³⁰ For instance by "calling in" projects for Ministerial review under the RMA.

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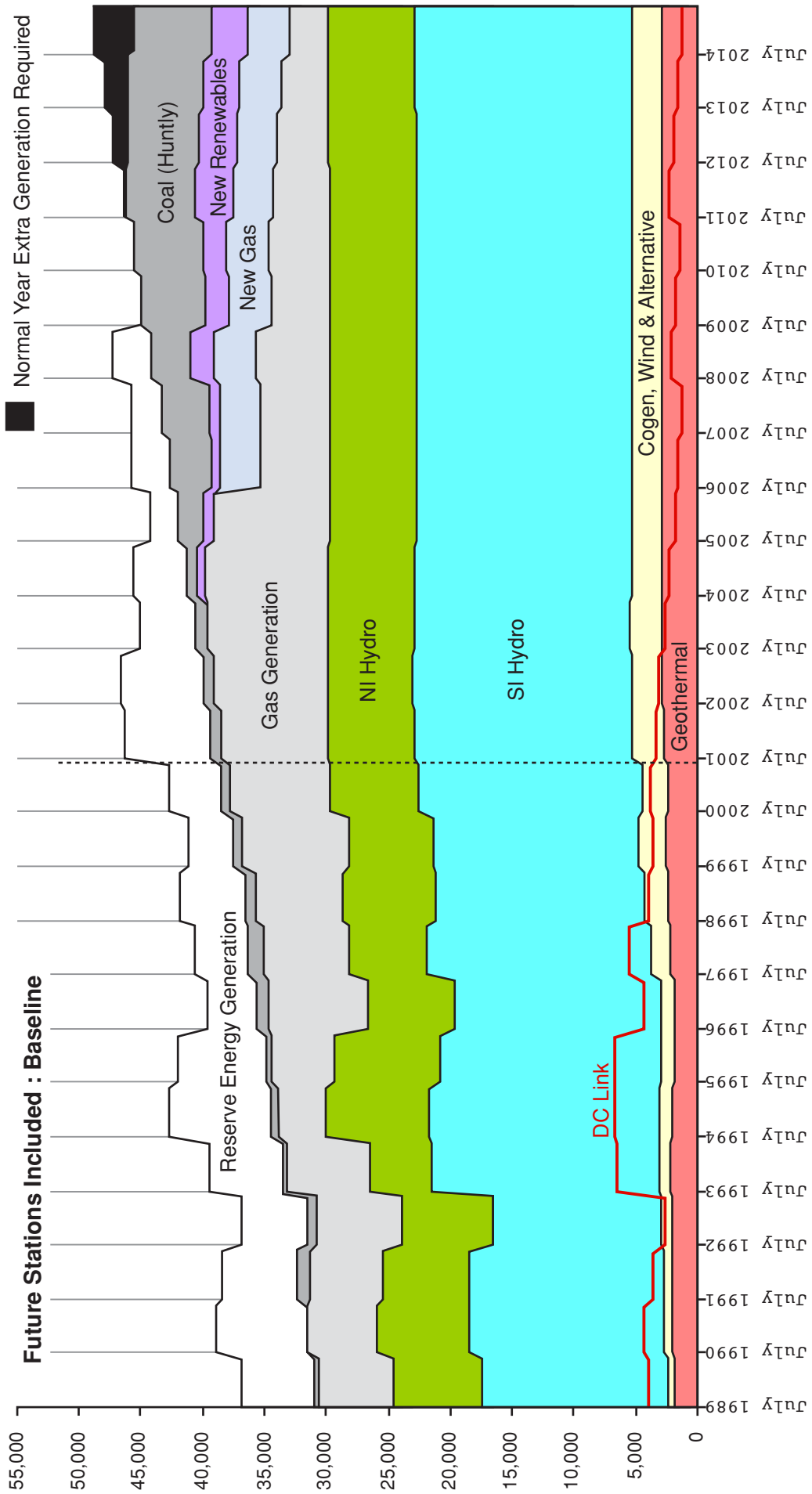


Chart 3: New Zealand Generation — Normal Hydro Inflows, Water Right loss assumed, Load Growth = 1.8%; Baseline Scenario for Future Stations

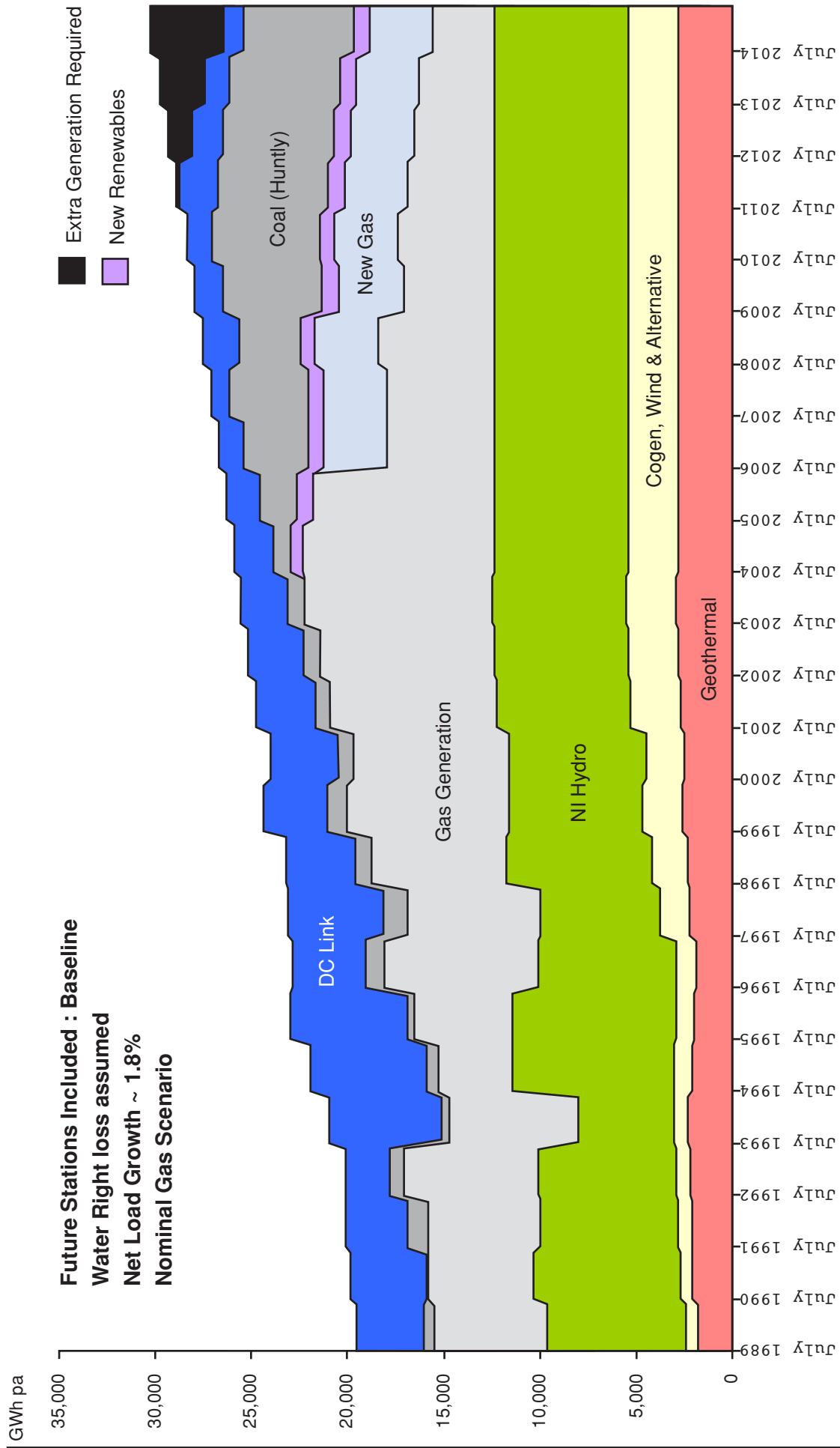


Chart 4: North Island Generation — Normal Hydro Inflows, Water Right loss assumed, Load Growth = 1.8%; Baseline Scenario for Future Stations

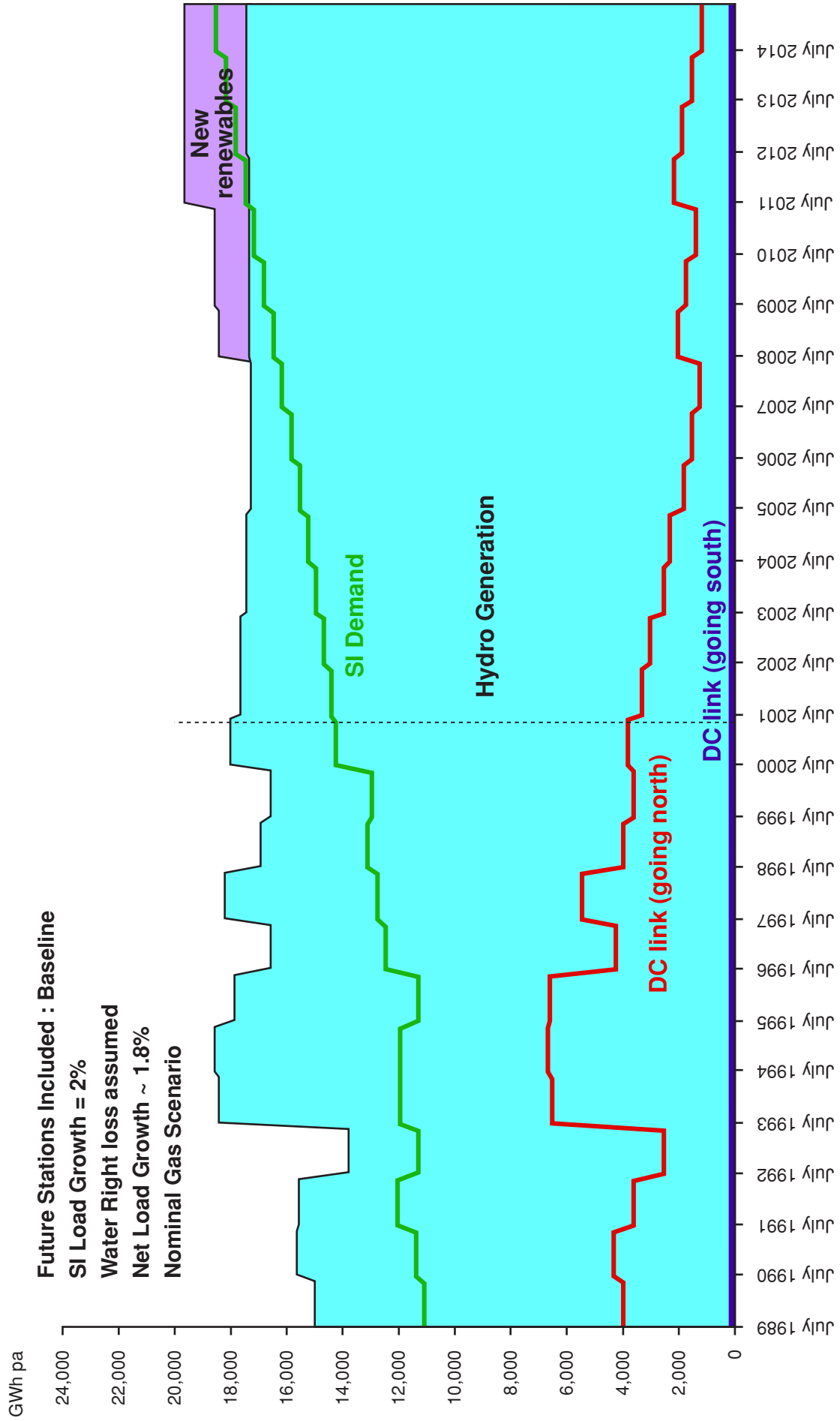


Chart 5: South Island Generation — Normal Hydro Inflows, Water Right loss assumed, Load Growth = 1.8%; Baseline Scenario for Future Stations

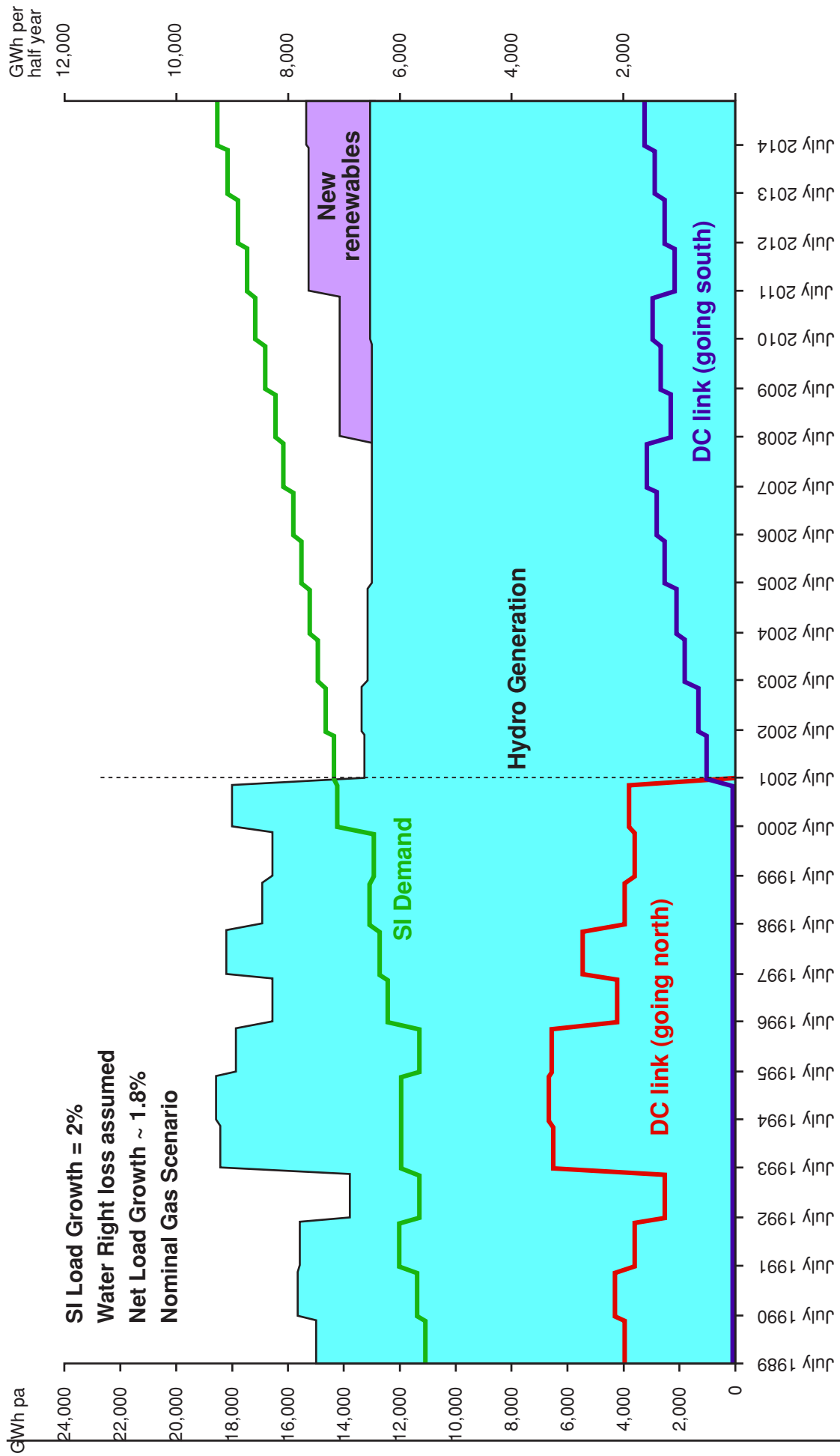


Chart 6: South Island Generation - Dry Year — Water Right loss assumed, Load Growth = 1.8%; Baseline Scenario for Future Stations

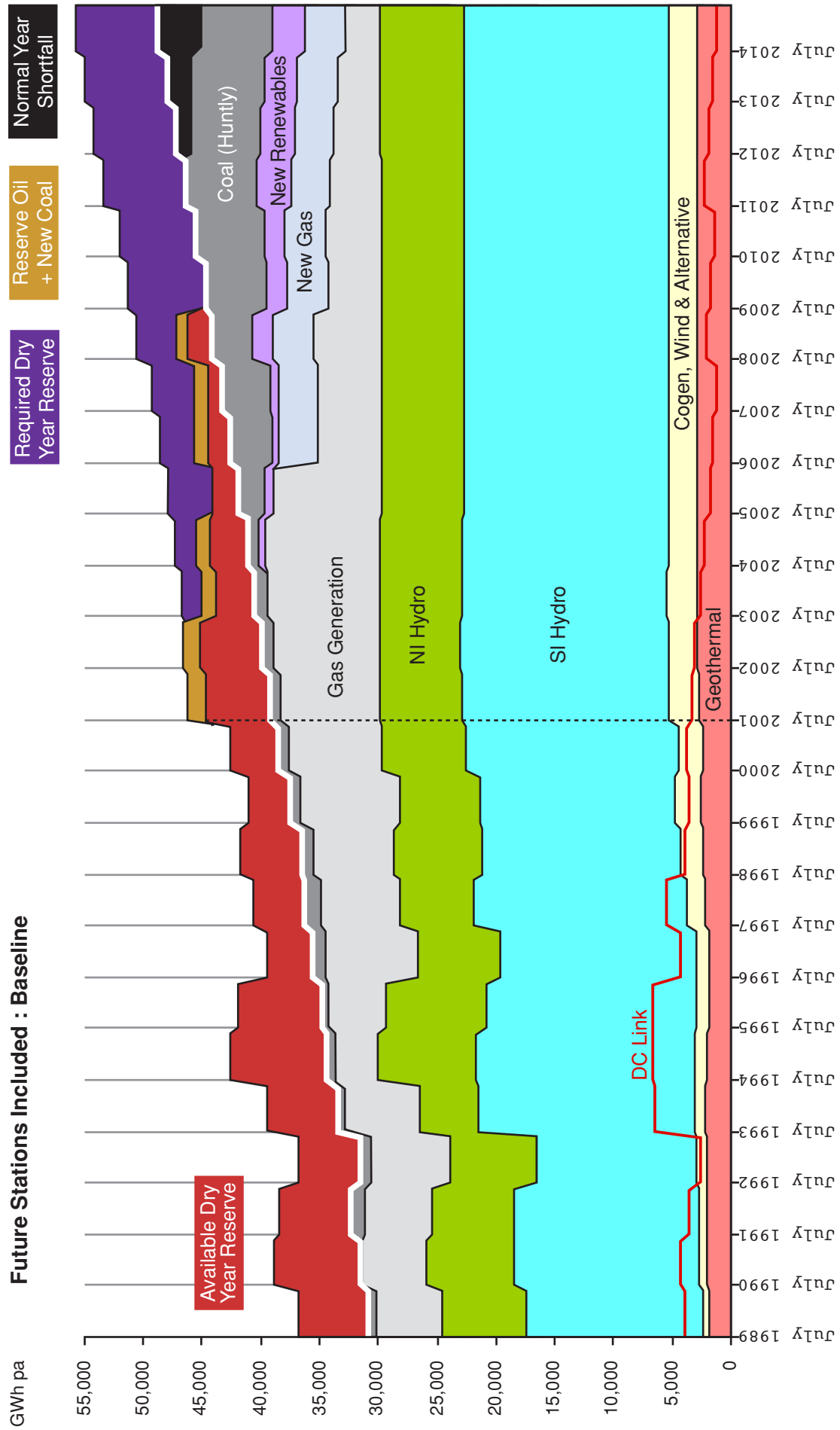


Chart 7: New Zealand Dry Year Reserves — Normal Hydro Inflows, Water Right loss assumed, Load Growth = 1.8%; Baseline Scenario for Future Stations

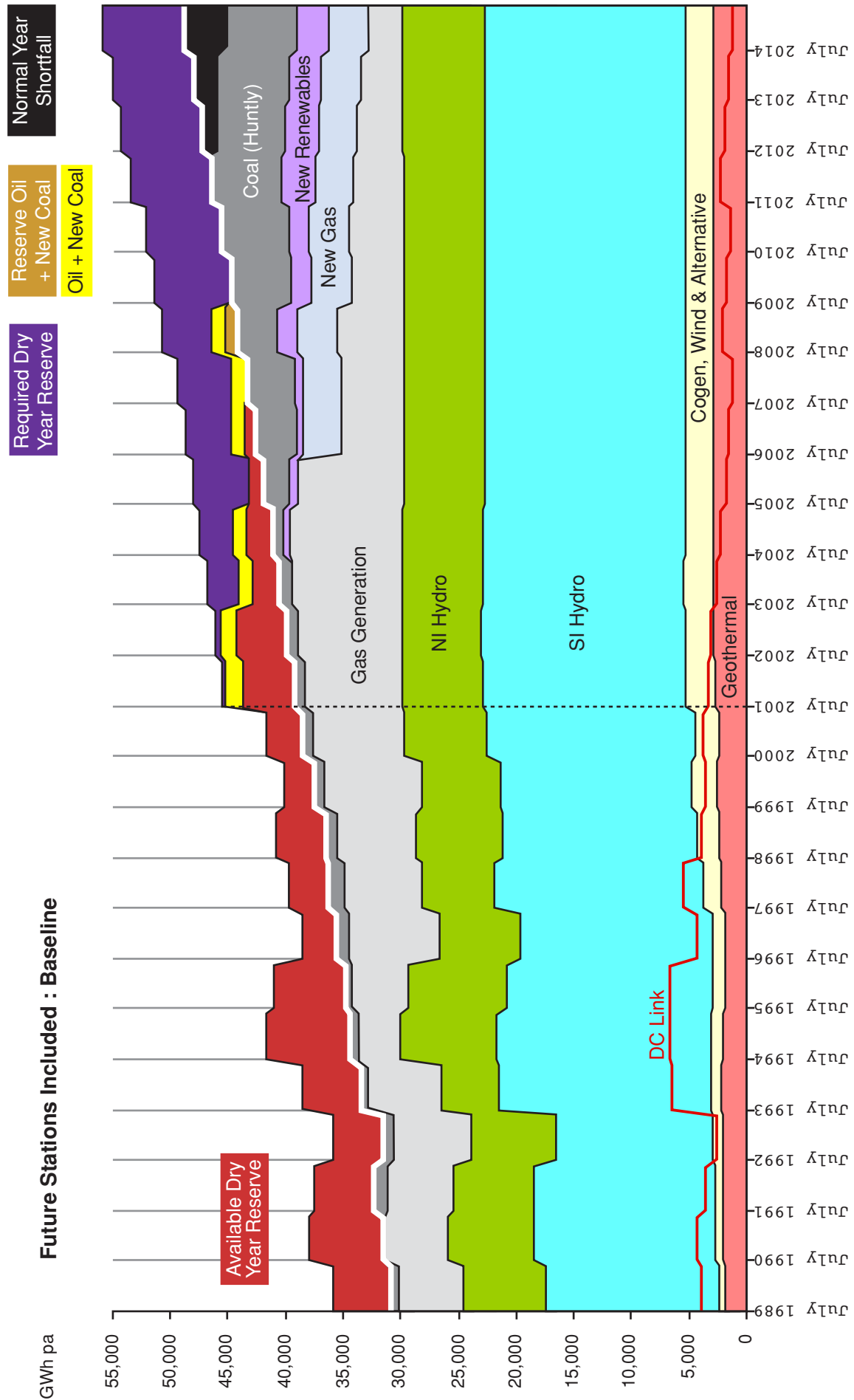


Chart 8: New Zealand Dry Year Reserves with a Unit Out-of-Service — Normal Hydro Inflows, Water Right loss assumed, Load Growth = 1.8%;
Baseline Scenario for Future Stations

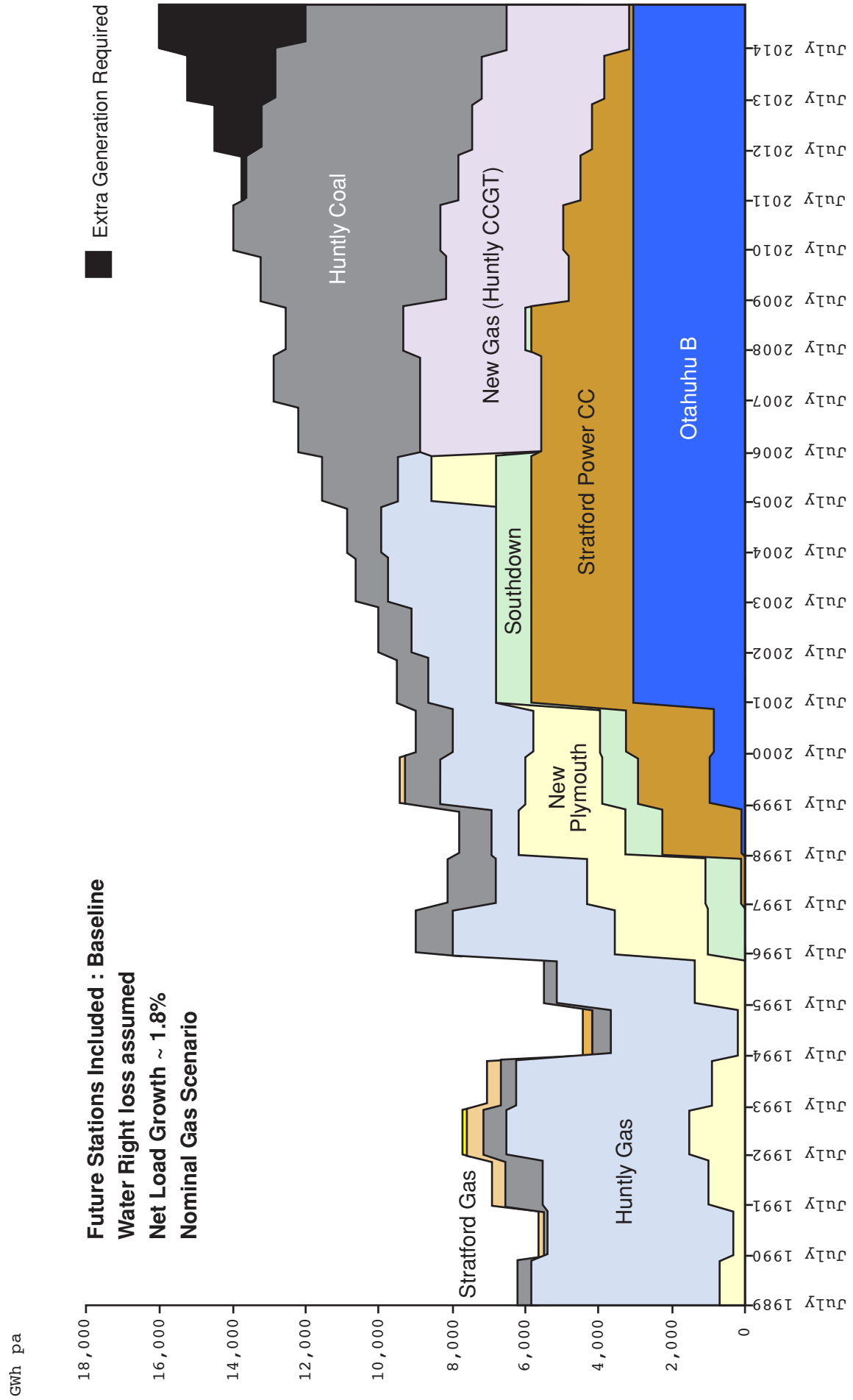


Chart 9: Generation by Fossil Fuel-fired Stations — Normal Hydro Inflows, Water Right loss assumed, Load Growth = 1.8%; Baseline Scenario for Future Stations

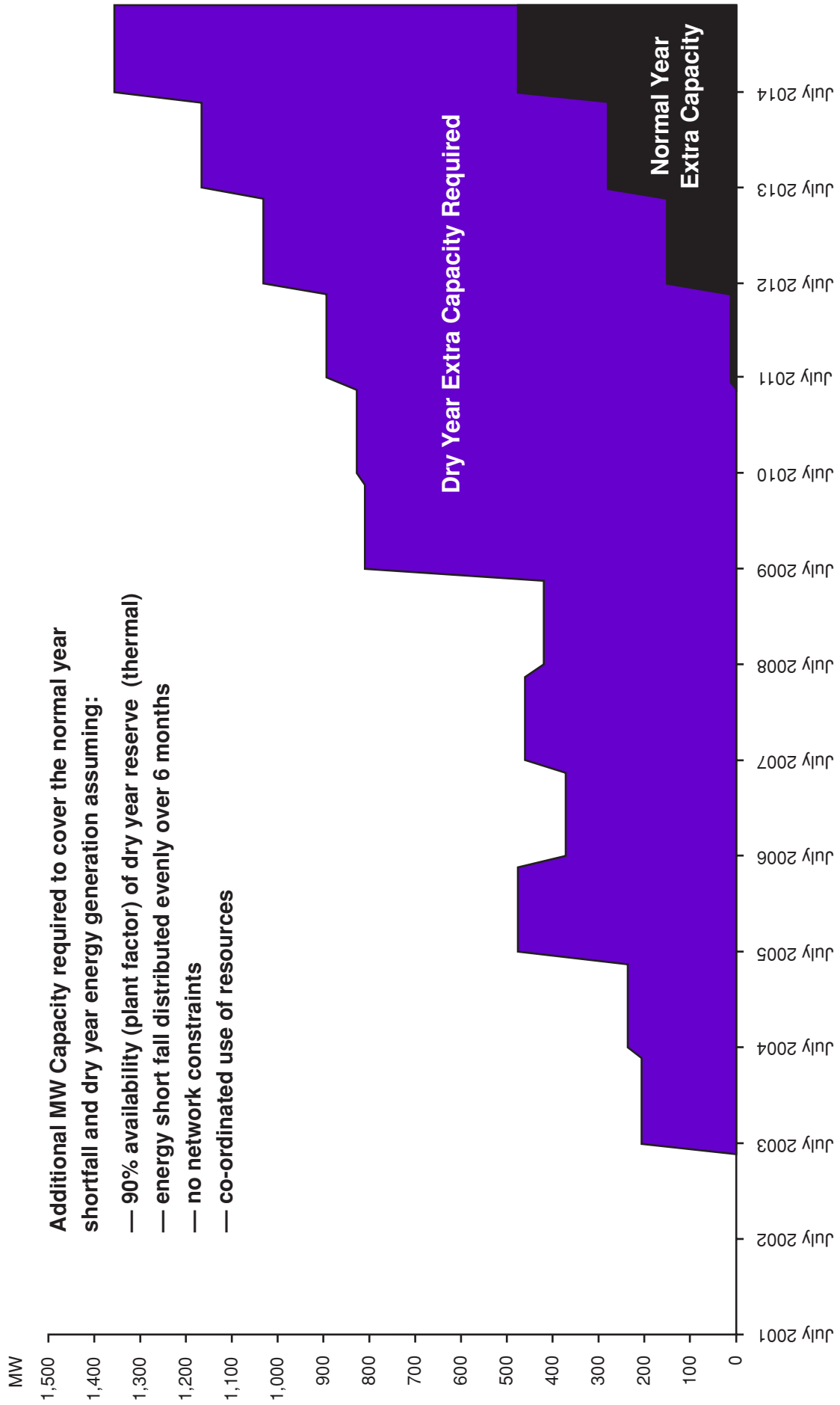
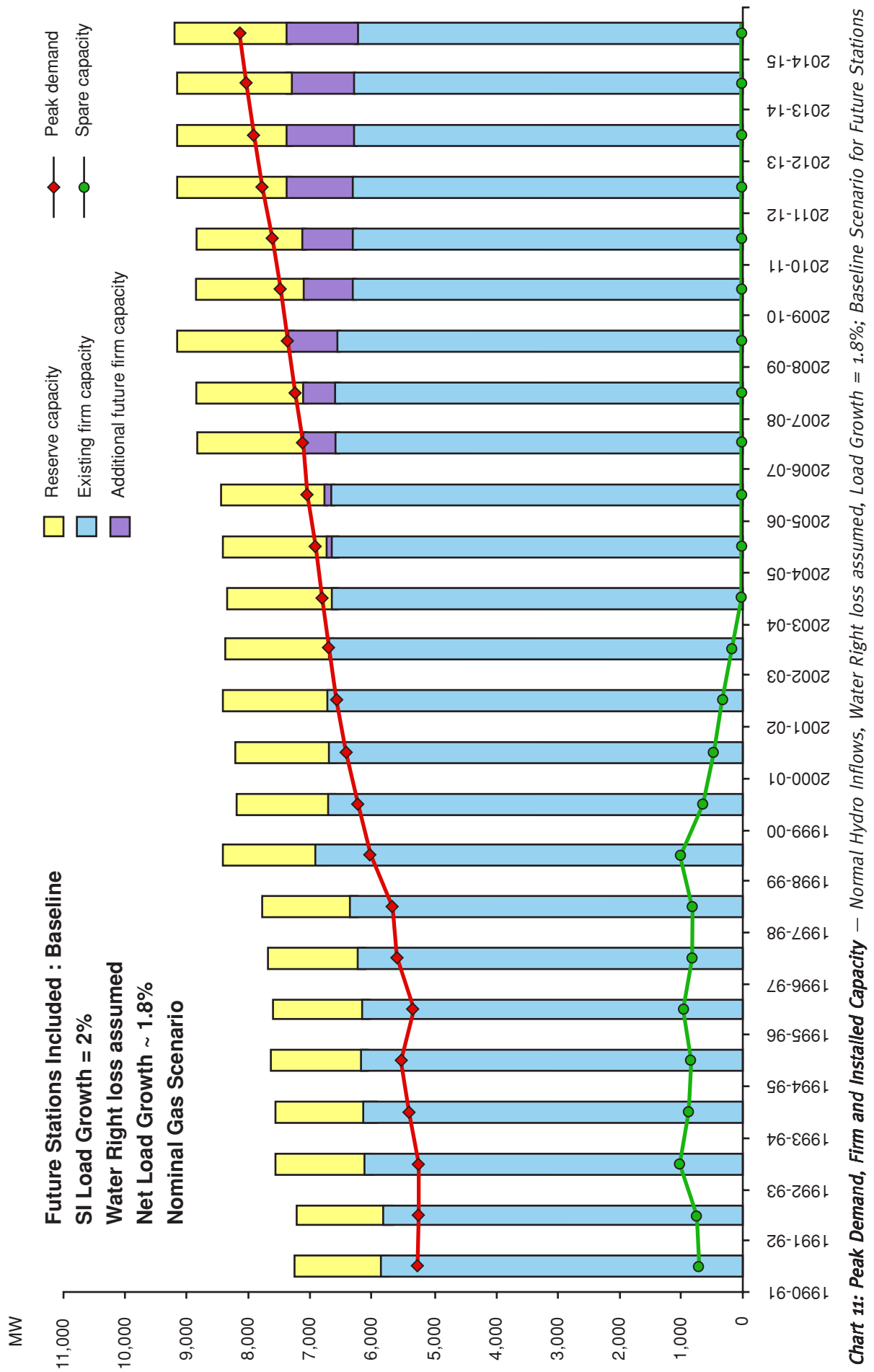


Chart 10: Additional MW Capacity — Normal Hydro Inflows, Water Right loss assumed, Load Growth = 1.8%; Baseline Scenario for Future Stations



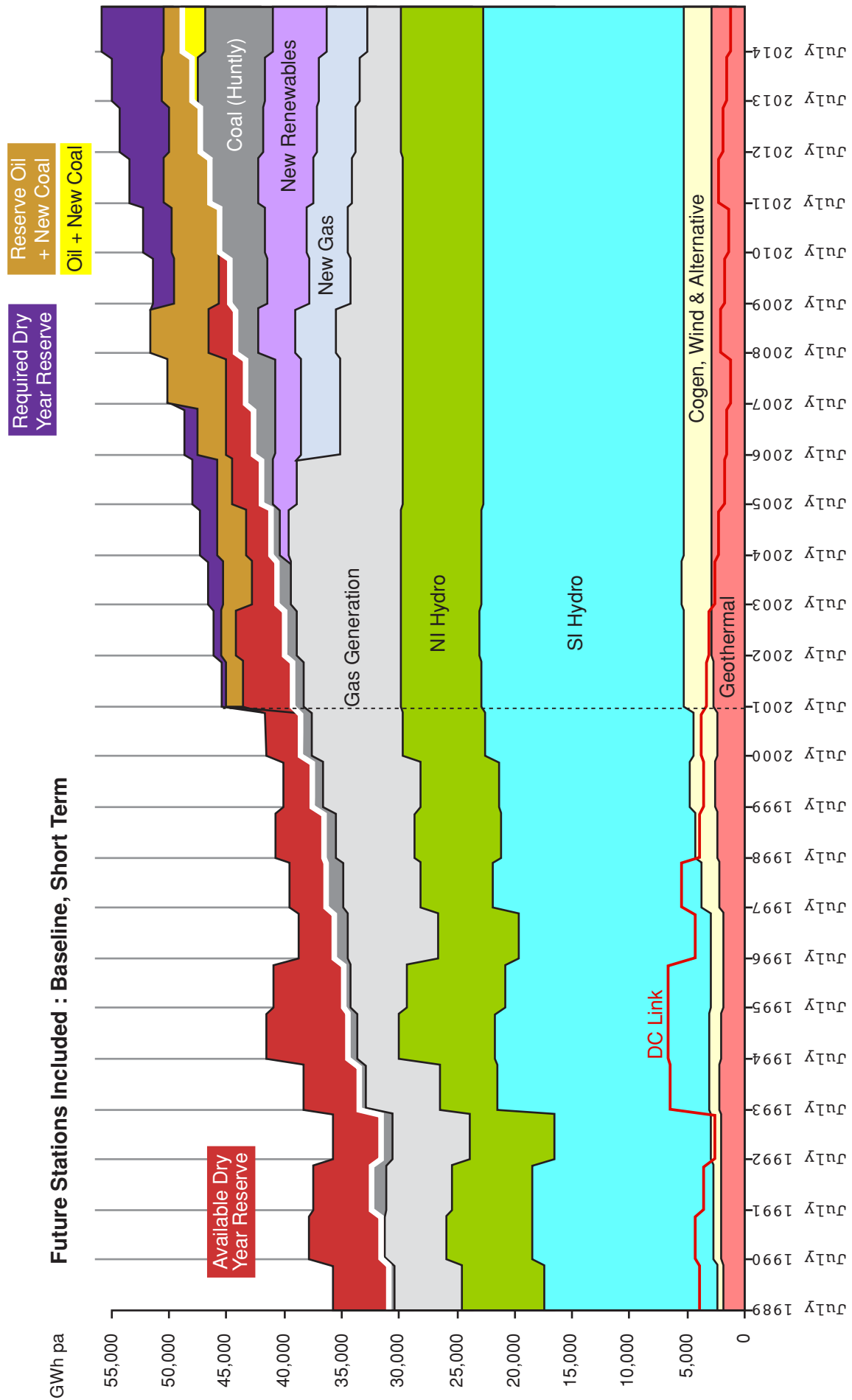


Chart 12: New Zealand Dry Year Reserves with a Unit Out-of-Service — Normal Hydro Inflows, Water Right loss assumed, Load Growth = 1.8%; Baseline and Short Term Scenario for Future Stations

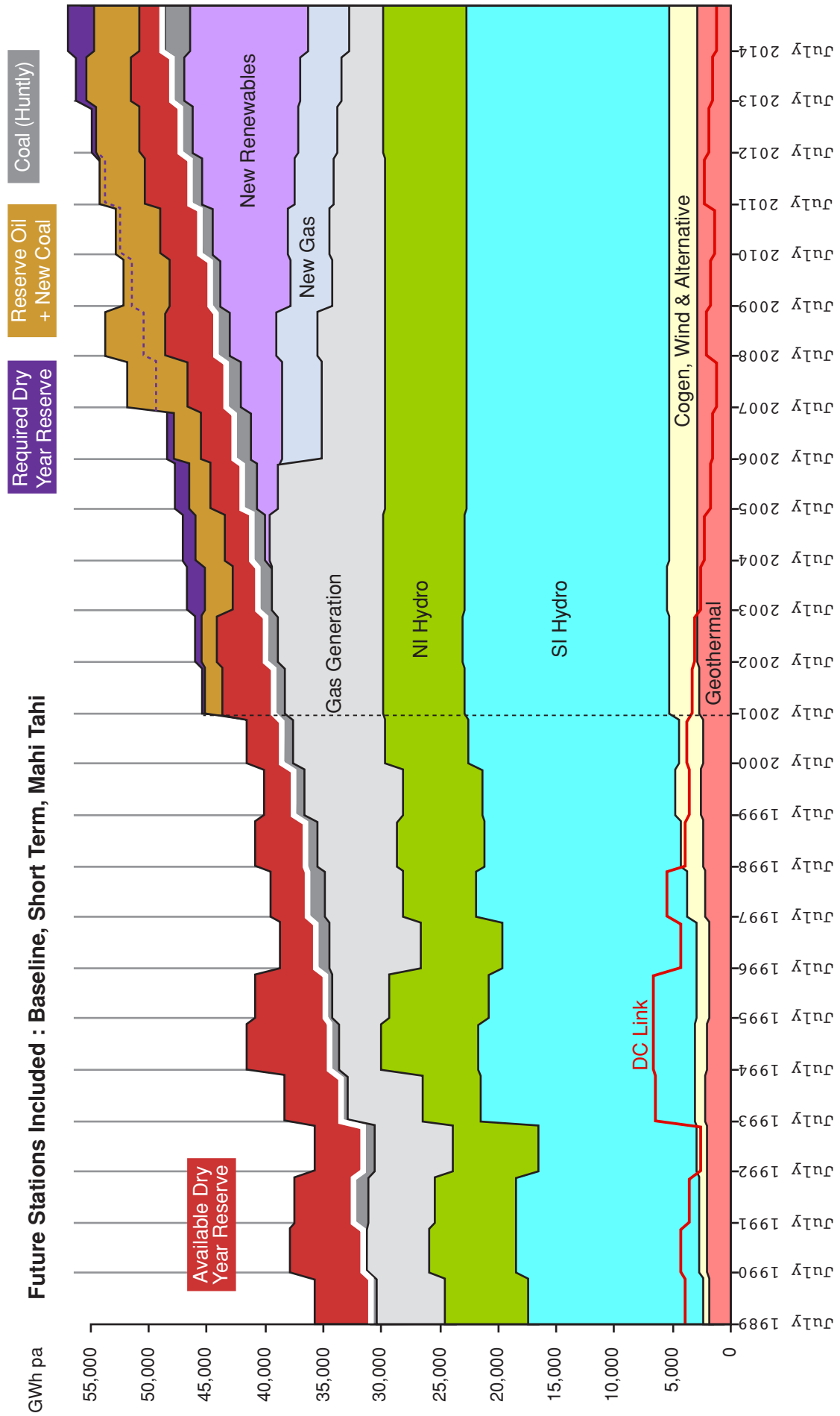


Chart 13: New Zealand Dry Year Reserves with a Unit Out-of-Service — Normal Hydro Inflows, Water Right loss assumed, Load Growth = 1.8%; Baseline, Short Term and Mahi Tahī Scenario for Future Stations

Appendices

| APPENDIX 2: INSTALLED CAPACITY (MW) | | 1989-90 | 1990-91 | 1991-92 | 1992-93 | 1993-94 | 1994-95 | 1995-96 | 1996-97 | 1997-98 | 1998-99 | 1999-00 | 2000-01 | | 2001-02 | 2002-03 | 2003-04 | 2004-05 | 2005-06 | 2006-07 | 2007-08 | 2008-09 | 2009-10 | 2010-11 | 2011-12 | 2012-13 | 2013-14 | 2014-15 |
|--|----------------------------|---------|---------|---------|---------|---------|---------|---------|---------|---------|---------|---------|---------|-----|---------|---------|---------|---------|---------|---------|---------|---------|---------|---------|---------|---------|---------|---------|
| North Island Thermal | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Fossil | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Contact Energy | New Plymouth | 575 | 575 | 575 | 575 | 575 | 600 | 600 | 600 | 600 | 480 | 400 | 400 | | 400 | 350 | 300 | 300 | 300 | 300 | 300 | 300 | 0 | 0 | 0 | 0 | 0 | 0 |
| Genesis Power | Huntly | 960 | 960 | 980 | 980 | 980 | 1,000 | 1,000 | 1,000 | 1,000 | 1,000 | 1,000 | 1,000 | | 1,000 | 1,000 | 1,000 | 1,000 | 1,000 | 1,000 | 1,000 | 1,000 | 1,000 | 1,000 | 1,000 | 1,000 | 1,000 | 1,000 |
| NGC | Southdown | | | | | | | | | | 120 | 120 | 118 | 118 | 118 | 118 | 118 | 118 | 118 | 118 | 118 | 118 | 118 | 118 | 118 | 118 | 118 | 118 |
| NGC | Stratford Power CC | | | | | | | | | | 350 | 354 | 354 | 354 | 354 | 354 | 354 | 354 | 354 | 354 | 354 | 354 | 354 | 354 | 354 | 354 | 354 | 354 |
| Contact Energy | Otauhu B | | | | | | | | | | 390 | 382 | 365 | | 365 | 365 | 365 | 365 | 365 | 365 | 365 | 365 | 365 | 365 | 365 | 365 | 365 | 365 |
| Contact Energy | Otauhu A | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Contact Energy | Stratford (decommissioned) | 200 | 198 | 198 | 198 | 198 | 198 | 198 | 198 | 198 | 198 | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Genesis Power (mothballed) | Meremere | 112 | 112 | | | | | | | | | | | | | | | | | | | | | | | | | |
| EONZ mothballed | Marsden A | 114 | 114 | 114 | 114 | 114 | 114 | 114 | 114 | | | | | | | | | | | | | | | | | | | |
| Contact Energy | Whirinaki (decommissioned) | 200 | 200 | 200 | 200 | 200 | 150 | 150 | 100 | 50 | 50 | | | | | | | | | | | | | | | | | |
| Geothermal | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Bay of Plenty Electricity | TOI & TG2, Kawerau | 2 | 2 | 2 | 2 | 2 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 |
| Contact Energy | McLachlan/Pohihi | | | | | | | | | | 53 | 53 | 53 | 53 | 53 | 53 | 53 | 53 | 53 | 53 | 53 | 53 | 53 | 53 | 53 | 53 | 53 | 53 |
| Contact Energy | Ohakaiki | 108 | 106 | 106 | 106 | 106 | 108 | 108 | 68 | 68 | 68 | 68 | 68 | | 68 | 68 | 68 | 68 | 68 | 68 | 68 | 68 | 68 | 68 | 68 | 68 | 68 | 68 |
| Contact Energy | Wairakei | 153 | 153 | 153 | 153 | 153 | 165 | 165 | 165 | 165 | 165 | 165 | 165 | | 165 | 165 | 165 | 165 | 165 | 165 | 165 | 165 | 165 | 165 | 165 | 165 | 165 | 165 |
| Tuaropaki Trust/MRP | Mokai | | | | | | | | | | | | | | 50 | 65 | 65 | 65 | 65 | 65 | 65 | 65 | 65 | 65 | 65 | 65 | 65 | 65 |
| Top Energy | Ngapahua Springs | 81 | 81 | 81 | 81 | 81 | 84 | 81 | 84 | 81 | 85 | 85 | 85 | | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 |
| Mighty River Power | Rotokawa | | | | | | | | | | 24 | 24 | 24 | | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 |
| Total Existing NI Thermal Capacity | | 2,424 | 2,440 | 2,328 | 2,328 | 2,332 | 2,341 | 2,301 | 2,334 | 2,284 | 2,914 | 2,632 | 2,630 | | 2,610 | 2,560 | 2,510 | 2,510 | 2,510 | 2,510 | 2,510 | 2,510 | 2,510 | 2,210 | 2,210 | 2,210 | 2,210 | 2,210 |
| Additional Future Fossil Fuel Capacity | | | | | | | | | | | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 400 | 400 | 400 | 400 | 400 | 400 | 400 | 400 |
| Additional Future Geothermal Capacity | | | | | | | | | | | | | | | 0 | 5 | 5 | 6 | 5 | 6 | 89 | 89 | 89 | 89 | 89 | 89 | 89 | 89 |
| Total NI Thermal Capacity | | | | | | | | | | | | | | | 2,610 | 2,565 | 2,515 | 2,519 | 2,599 | 2,999 | 2,999 | 2,999 | 2,699 | 2,699 | 2,699 | 2,699 | 2,699 | 2,699 |
| Cogeneration Plants | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Bay of Plenty Electricity | Edgecumbe Cogen | | | | | | | | | 10 | 10 | 10 | 10 | | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 |
| Bay of Plenty Electricity/NGC | Kapuni | | | | | | | | | 25 | 25 | 25 | 25 | | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 |
| Duke Energy | Glenbrook MHF & Kilns | 38 | 38 | 38 | 38 | 38 | 38 | 38 | 38 | 110 | 110 | 110 | 94 | 94 | 94 | 94 | 94 | 94 | 94 | 94 | 94 | 94 | 94 | 94 | 94 | 94 | 94 | 94 |
| Contact Energy/NZ Coop | Te Rapa | | | | | | | | | 45 | 45 | 45 | 45 | 45 | 45 | 45 | 45 | 45 | 45 | 45 | 45 | 45 | 45 | 45 | 45 | 45 | 45 | 45 |
| Genesis Power/Anchor Products | Te Awamutu | | | | | | | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 | 52 |
| Genesis Power/Carter Holt Harvey | Kinleith Mill | | | | | | | | | 34 | 34 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 |
| Kiwi Dairy Co (Todd) | Hawera | 39 | 39 | 39 | 39 | 39 | 39 | 39 | 39 | 20 | 40 | 40 | 65 | 65 | 65 | 65 | 65 | 65 | 65 | 65 | 65 | 65 | 65 | 65 | 65 | 65 | 65 | 65 |
| Tasman Pulp & Paper | Kawerau Mill | 39 | 39 | 39 | 39 | 39 | 39 | 39 | 39 | 39 | 39 | 39 | 39 | 39 | 39 | 39 | 39 | 39 | 39 | 39 | 39 | 39 | 39 | 39 | 39 | 39 | 39 | 39 |
| Various | Small NI Cogeneration | 81 | 80 | 81 | 81 | 81 | 84 | 81 | 85 | 85 | 85 | 85 | 85 | 85 | 85 | 85 | 85 | 85 | 85 | 85 | 85 | 85 | 85 | 85 | 85 | 85 | 85 | 85 |
| Total NI Cogeneration Capacity | | 157 | 157 | 157 | 158 | 158 | 212 | 213 | 243 | 395 | 440 | 455 | 455 | | 455 | 455 | 455 | 455 | 455 | 455 | 455 | 455 | 455 | 455 | 455 | 455 | 455 | 455 |
| Future NI Cogen Capacity | | | | | | | | | | | | | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Alternative Generating Capacity incl Wind | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Genesis Power | Hauauru Wind Farm | | | | | | | | 3.5 | 3.5 | 3.5 | 3.5 | 3.5 | | 3.5 | 3.5 | 3.5 | 3.5 | 3.5 | 3.5 | 3.5 | 3.5 | 3.5 | 3.5 | 3.5 | 3.5 | 3.5 | 3.5 |
| Meridian Energy | Wellington Wind Turbine | | | | | | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 |
| Mighty River Power | Rosedale / Greenmount | | | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 |
| TransAlta/Hutt City Council | Silverstream | | | | | | 3 | 3 | 3 | 3 | 3 | 3 | 3 | | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| TrustPower | Taranua Wind Farm | | | | | | | | | | | | | | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 |
| Total Alternative Capacity | | | | | | | 11.2 | 11.2 | 14.7 | 14.7 | 14.7 | 14.7 | 14.7 | | 46.7 | 46.7 | 46.7 | 46.7 | 46.7 | 46.7 | 46.7 | 46.7 | 46.7 | 46.7 | 46.7 | 46.7 | 46.7 | 46.7 |
| Future NI Alternative Capacity | | | | | | | | | | | | | | | 0 | 0 | 16 | 16 | 16 | 16 | 16 | 16 | 16 | 16 | 16 | 16 | 16 | 16 |
| North Island Hydro | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Bay of Plenty Electricity (Todd) | Aniwhenua | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 |
| Eastland Network | Wairua | 17 | 11 | 10 | 17 | 9 | 9 | 13 | 13 | 7 | 7 | 7 | 7 | | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Genesis Power | Kororarua | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Genesis Power | Rangipo | 120 | 120 | 120 | 120 | 120 | 120 | 120 | 120 | 120 | 120 | 120 | 120 | | 120 | 120 | 120 | 120 | 120 | 120 | 120 | 120 | 120 | 120 | 120 | 120 | 120 | 120 |
| Genesis Power | Tokaanu | 200 | 210 | 210 | 210 | 210 | 210 | 210 | 210 | 210 | 210 | 210 | 210 | | 210 | 210 | 210 | 210 | 210 | 210 | 210 | 210 | 210 | 210 | 210 | 210 | 210 | 210 |
| Genesis Power (to be sold) | Waikaremoana | 129 | 134 | 134 | 134 | 134 | 129 | 129 | 135 | 135 | 135 | 135 | 135 | | 135 | 135 | 135 | 135 | 135 | 135 | 135 | 135 | 135 | 135 | 135 | 135 | 135 | 135 |
| King Country Energy (Todd) | Kuratau | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | |
| King Country Energy (Todd) | Mangahao | 19 | 19 | 19 | 19 | 19 | 25 | 25 | 25 | 25 | 25 | 38 | 38 | | 38 | 38 | 38 | 38 | 38 | 38 | 38 | 38 | 38 | 38 | 38 | 38 | 38 | |
| King Country Energy (Todd) | Piraka | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | |
| King Country Energy (Todd) | Waierua Falls & Mokauti | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | |
| Mighty River Power | Arapuni | 160 | 160 | 160 | 160 | 160 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 | 175 |
| Mighty River Power | Araatiki | 84 | 84 | 84 | 84 | 84 | 84 | 84 | 84 | 84 | 84 | 84 | 84 | | 84 | 84 | 84 | 84 | 84 | 84 | 84 | 84 | 84 | 84 | 84 | 84 | 84 | 84 |
| Mighty River Power | Atiamuri | 79 | 79 | 79 | 79 | 79 | 79 | 79 | 79 | 79 | 79 | 79 | 79 | | 79 | 79 | 79 | 79 | 79 | 79 | 79 | 79 | 79 | 79 | 79 | 79 | 79 | 79 |
| Mighty River Power | Karapiro | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 |
| Mighty River Power | Maraetahi | 360 | 360 | 360 | 360 | 360 | 360 | 360 | 360 | 360 | 360 | 360 | 360 | | 360 | 360 | 360 | 360 | 360 | 360 | 360 | 360 | 360 | 360 | 360 | 360 | 360 | 360 |
| Mighty River Power | Ohakuri | 112 | 112 | 112 | 112 | 112 | 112 | 112 | 112 | 112 | 112 | 112 | 112 | | 112 | 112 | 112 | 112 | 112 | 112 | 112 | 112 | 112 | 112 | 112 | 112 | 112 | 112 |
| Mighty River Power | Waipapa | 51 | 51 | 51 | 51 | 51 | 51 | 51 | 51 | 51 | 51 | 51 | 51 | | 51 | 51 | 51 | 51 | 51 | 51 | 51 | 51 | 51 | 51 | 51 | 51 | 51 | 51 |
| Mighty River Power | Whakamaru | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | | | | |